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ENVIRONMENTAL IMPACTS
OF
ALTERNATIVE CONVERSION PROCESSES
FOR
WESTERN COAL DEVELOPMENT

DR. STEPHEN G. MILLER

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THOMAS E. CARROLL ASSOCIATES
WASHINGTON, D.C.

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October 25, 1974

Mr. Warren C. Wood, Federal Cochairman
Old West Regional Commission
1730 K Street N.W., Suite 426
Washington, D.C. 20006

Re: OWRC Contract #10470040

Dear Mr. Wood:

It is a pleasure to submit herewith our final report of "Natural Resources Use and Environmental Impact Study of Western Coal Development."

Those of us who have worked on the study would like to take this opportunity to congratulate the Commission for its support of such an innovative work, and, most particularly, to extend our thanks and appreciation for the willing cooperation of the Commission staff members, state officials in the Old West Region and private individuals who also have supported this effort.

It is our sincere hope that the benefits which you and your constituents derive fromthe application of the Report findings are as rewarding as it has been for us to develop the material.

Should you, or individual states, have further queries, we would be most happy to discuss them.

Sincerely,

Thomas E Carroll

TEC/kr

Enclosures

WASHINGTON CONSULTANTS TO INDUSTRY ON ENERGY AND THE ENVIRONMENT

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I. INTRODUCTION

A. Scope and Purpose of the Study

The U.S. recently has become painfully aware of its short supply of clean fuels. The vast coal reserves in the states of Montana, Wyoming, and North Dakota have prompted many private sector organizations to look toward the West for future saleable energy. The Federal government has joined the private sector by supporting numerous research and development efforts directed toward mining, converting, and transporting coal and its derivative products in a manner designed to decrease many of the presently noxious environmental effects associated with coal extraction and conversion.

Although the ultimate goal of utilizing coal to generate clean energy usable in populated urban areas is sound policy, federal, state, and local officials must not neglect the potential environmental and social impacts in the region where the coal is extracted and converted to the clean energy source. It is with this concern in mind that the Old West Regional Commission has engaged Thomas E. Carroll Associates to examine a number of potential coal conversion schemes in order to determine the environmental impacts associated with extracting the requisite coal and possibly locally converting it to a clean energy source for export out of the region.

Section I of this study will systematically examine the inputs needed to successfully appraise a detailed environmental impact analysis for any feasible type of coal conversion project in the "Old West" Region. Where available, quantitative estimates of pollutant parameters will be given. Where quantitative estimates are not available, a discussion of the possible numerical range of values and recommendations for future research will be given. Furthermore, it is the intention of the study not only to allow evaluation of impacts of proposed projects, but also to allow regional planning efforts to be based on a determination of the mix of potentially commercial processes with respect to aggregated environmental damage and economic benefits.

Section II of this study will investigate the potential adverse effects of the emissions, water and land use parameters identified in Section I. Although no emission modelling with be performed, a possible range of ambient conditions will be discussed with respect to ecological, and human health and welfare considerations. Present Federal ambient standards and potential future standard changes will be reviewed for air and water pollutants. Additionally, the effects of some unregulated pollutants will be discussed. Finally, the issue of strip mined land reclamation will be reviewed with reference to the latest literature available. Section II will aid the planner in foreseeing the possible effects of certain processes on a variety of environmental parameters for which no suitable regulatory measures presently exist for redress.

B. Processes to Be Investigated

The processes to be examined include seven different coal gasification processes, two coal liquefaction processes, electric power generation including steam cycle, gas turbine, magnetohydrodynamic, and various combined cycle generation systems. This study will not attempt to judge the economic or technical feasibility of the processes to be evaluated. However, all processes considered were chosen by the authors because they appeared to have sufficient merit to make it possible for them to be commercially in-use within 15 years.[a] In all but one case coal for conversion is assumed to be extracted via area surface mining. The single exception is that of in-situ gasification in which coal is gasified by controlled steam injection directly into the coal seam.

It is very important to realize that many parameters for these processes are not well defined at this time. An example is the Lurgi-type gasification plant proposed for construction on Navajo lands in New Mexico. The original cost estimate was between \$250 - \$300 million. The present estimate is closer to \$650 million. Much of the increased cost is required for upgraded and more intensive pollution control apparatus and more sophisticated cooling methods to limit water use. Therefore, when potential pollutant outputs from processes are discussed it should be realized that these outputs may be limited by further controls, which have not yet been factored into the present design concepts. The possibility of further controls will be continually discussed within the report.

---

[a] All of the processes discussed have at least realized the pilot plant stage.

C. Environmental Parameters

The critical environmental parameters to be examined for each process include airborne emissions, water emissions, water use, solid waste and land distrubance, as they arise both directly from the process itself and from the domestic population (comprising the labor force for the process and the mining operation) and their dependents, and the requisite service personnel and their dependents. It is realized that each "real world" geographic project area would have its own specialized set of baseline environmental conditions, and therefore a range of potential environmental damages is to be discussed (in Section II) with respect to the different types of potential baseline conditions existing for the air, water, and land conditions in the region (e.g., it is known that sulfuric acid in rain water severely affects acidic soils, but may actually aid in neutralizing alkaline soils).

The report will first include (in Section I) a description of each conversion process, its economically desirable size and requisite labor force as well as the coal type for which it is best suited (to give an idea of its potential use in the "Old West" Region). Then the actual effluents and natural resource usages will be examined for each conversion process and for the requisite mining operation.

Finally, the environmental damage potentials of the various pollutants and type of land disturbance will be discussed (in Section II) both with reference to currently regulated pollutants and with respect to substances which have known adverse effects, but which are not yet under regulation (e.g., suspended sulfate particulates).

A discussion of the known and potential environmental damages arising from coal extraction methods will follow the pollutant section.

II. PROCESS DESCRIPTIONS

In order to fully understand the pollutant and water use problems associated with each process, a description follows of how each of the various processes works.

A. Coal Gasification

1. General concepts and the chemistry of gasification

The concept of converting coal into a gas for fuel is by no means new. It was used by the British in the late 19th and early 20th century to make very low heating value gas called "town gas". The Germans used the Lurgi process to manufacture gas from coal before and during World War II. The gas produced had a medium heating value rating. Today there are two directions being taken in coal gasification.

First there is the need for high heating value gas to go into natural gas pipelines for domestic, utility and some industrial uses. The synthetic gas produced for use in such pipelines would have to meet Federal Power Commission (FPC) standards with respect to minimum heating value, flow properties, and trace gas composition. The synthetic pipeline gas processes aim at achieving heating values above 950 BTU[b] per standard cubic foot (SCF). In order to achieve such a high heating value, the final product of the first gasification step (a low BTU gas containing some methane-CH_4-, Hydrogen-H_2-, Carbon Monoxide-CO-, and undesirable gases) needs to be further reacted to form methane from the H_2 and CO.

---

[b] A BTU is that amount of heat necessary to raise one pound of water one degree Fahrenheit.

This methanation step is new and is presently being applied by Lurgi to a pilot plant in South Africa.

The other direction in which gasification efforts are proceeding is in the conversion of coal at a medium (or low) BTU (400-500) gas to be used adjacent to (or within no more than 200 miles of) an electric utility or large industrial user. The gas is too low in heating value to be transported any great distances, because the transportation expense would offset its low price advantage. Such gas would be a product of the first gasification step mentioned previously and would require no further methanation. Its value lies in its being able to power gas turbines for electrical generation, fire industrial boilers, or be a source of hydrogen for ammonia manufacture or petrochemical hydrogenation processes.

The pollution problems and natural resources uses will vary according to the nature of the process. The high-BTU processes require larger labor forces for operation and maintenance of the plants than the low BTU processes. The optimal plant size itself is dependent on the final marketable product, its cost and the price that can be received. These economic variables will ultimately effect the labor force concentrations in specific areas.

In the production of high BTU pipeline gas, processes differ primarily in the means of supplying heat to the gasification step, the method of introducing the coal into the gasifier, and the method of maintaining contact between the coal and the reacting gases (H_2O, CO, H_2). Some basic principles concerning the chemical nature of coal follow:

Coal is composed of organic carbon, hydrogen, oxygen, sulfur and nitrogen compounds, and an inorganic ash fraction composed mostly of inert silica (SiO_2) and alumina (Al_2O_3)[c] along with calcium (Ca), sodium (Na), iron (Fe), potassium (K), chloride (Cl), bicarbonate (HCO_3) and sulfide (S) salts, as well as trace elements such as mercury (Hg), cadmium (Cd), zinc (Zn), copper (Cu), arsenic (As), etc. Furthermore, most coal will have a moisture content of between 10 - 30 percent.

The quantity of ash, sulfur, nitrogen, and trace elements will vary from coal type to coal type. The nitrogen is chemically contained within the organic fraction, while the sulfur is generally split between the organic and inorganic fractions. The organic coal fraction consists of large molecules containing three to four 6-carbon rings. The heating value of coals depends strongly on the ash and moisture contents as well as the hydrogen to oxygen ratio.[1]

Upon heating coal in the presence of air (combustion), carbon dioxide, water vapor, inert ash, sulfur dioxide (SO_2) and trioxide (SO_3), and nitrogen are formed. However, at high temperatures (over 1900° F), nitrogen and oxygen from the air combine to form nitrogen oxides (NO_x). Furthermore sometimes the combustion is incomplete allowing aromatic hydrocarbons to vaporize and become part of the flue gas. Finally, at high temperatures, the gaseous flue gas may contain volatile components from the ash. Mercury, arsenic, selenium, sodium chloride, and potassium chloride would be examples of such volatile components.

---

[c] These are typical inert inorganic components of soil.

When coal is heated in an inert atmosphere, as in the coking process (pyrolysis), it partially decomposes to form volatile (gas phase) organic compounds and steam, and a solid phase referred to as char, which is mostly elemental carbon and the inorganic ash fraction.[2] The gas phase organic molecules would include benzene, methyl and ethly benzenes (the light oil fraction), phenols, and large fused benzene ring compounds (the tar fraction). At sufficiently high temperatures (above 1700° F), almost all of the organic compounds decompose to carbon and hydrogen and then quickly react to form methane. These phenomena are important in order to understand the processes of coal gasification, electric power generation from combustion, and coal liquefaction.

The gasification processes may be conveniently divided into two general categories -- fixed bed and fluidized bed. The fixed bed processes, developed by Lurgi and Koppers are so named because they refer to the fact that the solid coal sits in a fixed place while reacting with steam in the gasifier. The disadvantage of such processes is that the coal's reactive surface area is not maximized, thus requiring a long residence time for the coal in the gasifier. Fluidized (or entrained) beds refer to the fact that the coal is in a pulverized form and is effectively maintained in small particles in a suspended state (generally by upward steam pressure). This maximizes the reactive surface area, thereby decreasing residence times in the gasifier, ultimately resulting in greater coal throughputs in similar times than with fixed bed processes. Furthermore, higher heat value conversion efficiencies are expected with fluid bed processes. All of the major new American processes for pipeline-quality gas utilize a fluid (or entrained) bed concept. These latter include the Institute of Gas Technology's "Hygas" process, the Bituminous Coal Research "BiGas" process, the Bureau of Mines "Synthane" process, and Consolidation Coal's "CO_2 Acceptor" process. The disadvantage of these processes is that they require high pressure turbulent mixing to keep the beds fluidized, thereby necessitating sophisticated solid and fluid control systems.

The desired end product from coal **gasification is methane** (CH_4). While the carbon-to-carbon ratio in methane is 1:4, coal only has about a 1:1.5-2 ratio (including the hydrogen from the moisture in the coal). The remainder of the hydrogen required for methane production comes from coal reactions with externally supplied water. The reactions in the gasification processes can be simplified as follows:

(1) water + carbon -> hydrogen + carbon monoxide

$H_2O + C \rightarrow CO + H_2$ (heat is required)

(2) direct methanation

$2H_2 + C \rightarrow CH_4$ (heat is given off)

(3) the shift reaction

$H_2O + CO \rightarrow H_2 + CO_2$ (heat is given off)

(4) catalytic methanation

$3H_2 + CO \rightarrow CH_4 + H_2O$ (heat is given off)

In all high BTU gasification processes, the first step (after devolatization) is reaction (1), which requires a heat input in order to occur. The next steps demonstrate the process differences. Some processes attempt to maximize reaction (2), while others attempt to get the proper H_2:CO ratio in reaction (3), in order to optimize the methane yield in reaction (4). However, all of the processes ultimately require the same amount of hydrogen in order to make the same quality of methane from the same quantity of coal. This implies that the water actually used as a hydrogen source directly in the process is a constant regardless of the nature of the process. The method for obtaining a successful process includes minimizing the time needed to achieve maximum methane production, while simultaneously optimizing the use of the heat output from reactions (2)-(4) to make reaction (1) go. The net energy balance is negative, meaning that energy is always expended when making methane from coal both in terms of supplying heat for reaction (1), and to make steam or electrical energy to operate compressors, pumps and other mechanical equipment.

After reactions (1) and (2) take place in the gasifier, reaction (3) may or may not be needed. However, before reaction (4) takes place, all of the particulate, CO_2, hydrogen sulfide (H_2S), tars and oils, ammonia (NH_3), and volatile metals and inorganic salts must be removed from the gasifier product gas (gas cleaning),or else they will adversely affect the catalyst required for reaction (4). Each process uses about the same technology to perform gas cleaning, but the quantity of waste material will differ, therefore creating differing waste water and waste gas streams. It should also be noted that there will be different cooling requirements for the processes as well as different ash disposal problems. Finally, it should be carefully noted that the method of supplying process heat will be very different from method to method, and this is the point where environmental impacts can differ substantially.

2. The Processes

In all cases, it will be assumed that, because the western coals of concern to this report (i.e., lignite and subbituminous) are non-caking, no caking preventative pretreatment will be required as is generally required for eastern and midwestern coals.

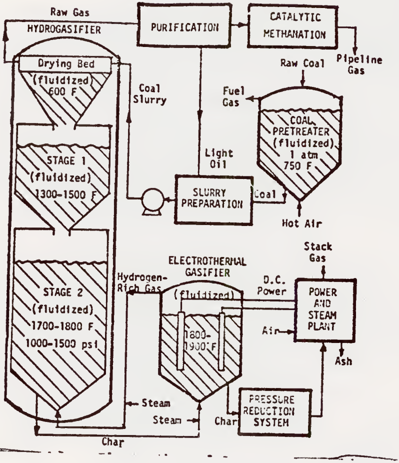
(a) HyGas Process

The Institute of Gas Technology's (IGT) HyGas process comes in two varieties (i.e., with heat supplied electrically or by char combustion with oxygen). The coal is slurried with oil, pumped to a drying bed where the slurry is sprayed onto a fluidized bed at about 600° F. The coal (in the oxygen version) then begins to fall and it encounters H_2, CO, and steam rising from the bottom of the unit (second stage). Devolatilization and methanation occur here (1300-1500° F). Then the gasification and methanation steps (i.e., production of H_2, CO, CH_4) occur (1700-1800° F). The remaining char is then withdrawn to another chamber. In the electrothermal process, the chamber is heated electrically to allow the char to react with steam at 1800-1900° F, creating a gas rich in H and CO which will go to the first unit.

If the system is heated by char and oxygen, then the char in the chamber reacts with steam and pure oxygen, generating the H_2 and CO which is sent back into the first unit. Pure oxygen is desired because nitrogen in air acts as an unwanted diluent and reactant. (See Fig. II-1). The ash is withdrawn and quenched from this chamber. The raw gas leaving from atop Stage I is cooled, and ammonia, tars, and oils are removed. It is next stripped of H_2S and CO_2, and sent to the catalytic methanator. The process may be used for all coals.

Fig. II-1

Schematic Flow Diagram of the HyGas Electrothermal Process*



*See Reference 34.

(b) BiGas Process

A pulverized coal slurry is injected with steam into the upper stage of a two-stage gasifier. The temperature of this stage is between 1400-1700° F, where it devolatilizes and is partially methanated by the H_2 and CO rising from the hotter lower stage (see Fig. II-2). The char and gas from this stage rise and leave the gasifier. The char is captured by a cyclone particle collector, and recycled to the lower section for gasification and combustion with steam and oxygen, respectively (the combustion heat generating the requisite heat for gasification). This takes place at 2700-2800° F. At these temperatures, the ash (remaining after the char carbon is all used) is in a molten form known as a slag. The slag flows down the chamber where it is withdrawn and quenched to a glassy substance in water. The product gas leaving is then cooled, purified and methanated. The process is useful for all coals.

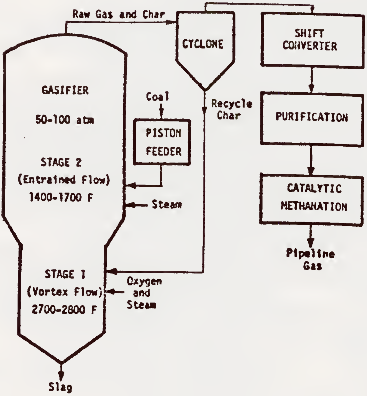
(c) CO_2 Acceptor Process

This process is unique in that the direct heat supplied to the gasification reaction is supplied via a non-coal related chemical reaction. The reaction used is that of dolomite (a mixture of magnesium and calcium oxides, MgO-CaO) with CO_2 (evolved during gasification) to form magnesium and calcium carbonate: $CaO + CO_2 \rightarrow CaCO_3 + \text{heat}$.

Lignite is fed, via lock hoppers, into the upper stage of a fluidized two-stage gasifier (see Fig. II-3) at 1500° F where it is devolatilized and reacted with gas rising from the lower stage

Fig. II-2

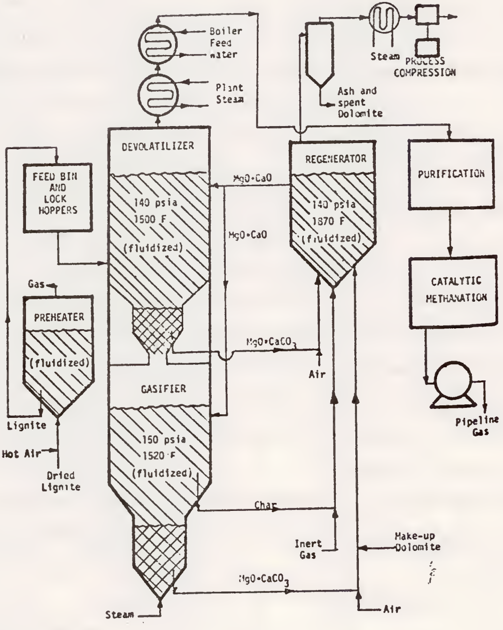
Schematic Flow Diagram of the BiGas Process*



*See Reference 34.

Fig. II-3

Schematic Flow Diagram of the CO_2 Acceptor Process*



*See Reference 34

(1520 ° F) where gasification occurs with steam. At the bottom of this stage, the reacted dolomite and char is withdrawn.

The char-dolomite mixture is then sent to a regenerator where the char is reacted with air (combusted) to yield the heat necessary to drive off CO_2 and regenerate the original dolomite for reuse. The product gas is cooled, purified and methanated.

There are two economic advantages to the CO_2 Acceptor process. The first is that air may be used rather than pure oxygen in the heat producing combustion step. This is so because the regenerator is separated from the gasifier, thus preventing product gas contamination by the nitrogen and carbon dioxide of the air. The advantage of air over oxygen is that an energy intensive air separation plant (to produce pure oxygen) is not required. This reduces both the initial capital and operating cost of the plant. The second advantage is that because CO_2 is removed from the reacting gases, equilibrium methane production in the gasifier is shifted toward quantities greater than normally attained at those temperatures were the CO_2 were not removed. This reduces the cost of the final methanation step.

The CO_2 Acceptor process has been developed primarily for use with lignite and therefore will be primarily applicable to North Dakota and Wyoming.

(d) Lurgi Process

The Lurgi process is the only gasification process discussed here which has been used commercially (although only for production of low BTU gas). It is a fixed bed process in which sized coal enters from the top of the gasifier chamber (see Fig. II-4). Steam and oxygen enter the chamber from the bottom. There is a reaction zone in the center of the chamber. Ash is removed from the bottom of the chamber where it is quenched. Product gas leaves the chamber from the top where about half of it is shifted and cooled. All of the product then goes through a gas purification process and then to a methanation unit. The process is amenable to use with non-caking subbituminous coals. Presently, El Paso Natural Gas Company and the Texas Eastern Transmission Company have plans to construct Lurgi process plants on the Navajo Reservation in northwestern New Mexico. However, there is some doubt whether the process can use the lignite. The difficulty arises from the fact that when lignite is heated it quickly dries out and crumbles. The Lurgi process, however, requires the coal to remain a given size in the gasifier. This may create problems for the proposed Michigan-Wisconsin Gas Company Lurgi Plant in North Dakota.

(e) Synthane Process

The synthane process (developed by the Bureau of Mines) is similar to a fluidized bed version of the Lurgi process. Coal, steam, and oxygen are introduced into the top of the gasifier chamber at 750° F where partial devolatilization occurs. (see Fig. II-5). The coal begins to fall in a fluidized state through two stages (1100-1450° F and 1750-1850° F, respectively), where reaction and further devolatilization occur. Char is removed from

Fig. II-4

Schematic Flow Diagram of the Lurgi Process*

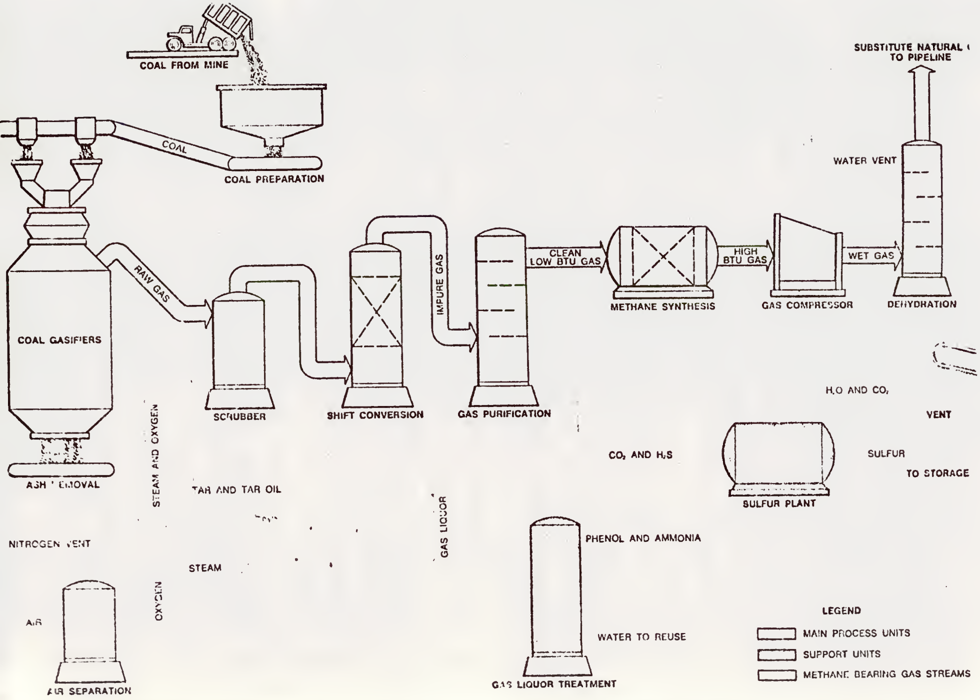
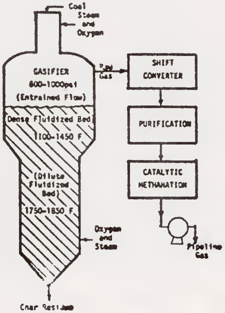


Fig. II-5

Schematic Flow Diagram of the Synthane Process*



*See Reference 34.

the bottom and the product gas from the top. The gas is next shifted, purified, and methanated.

(f) In-situ Processes

The concept of in-situ gasification was originated in the mid-19th centruy. Recently, attempts have been made to gasify shallow subbituminous coal deposits in Germany and the U.S.S.R. Conceptually, the idea is to leave thick coal deposits in place, fracture the coal seam, introduce oxygen and steam at surface apertures and collect a product gas at another surface aperture. The economic advantages of such a process are obvious, i.e., there is no need to mine and transport coal to a plant site, and there is no need to construct a gasifier for gas production.

The longest operating underground gasification unit was in Russia (1933-1965)[3]. The gas from this process was used for electric power generation, indicating that the process was controlled rather consistently. There have been two major American efforts to gasify coal underground. The first was at Gorgas, Alabama, in the 1950's. That effort was ended due to its unfavorable economics at that time. A more recent effort has been undertaken by the Bureau of Mines at Hanna, Wyoming.[4] That project is currently producing 2.5 million standard cubic feet (SCF) per day of low BTU gas. In all of these projects, the coal fracturing was done by drilling and applying hydraulic pressure. However, recently a group at the Lawrence Livermore Laboratory[5] has proposed a process in which the coal seam would be fractured by conventional explosives in order to obtain the desired permeability and surface area requirements.

The major problems encountered in the process arise from the difficulties inherent in controlling the temperature of the gasifying coal, controlling the seepage of ground water into the gasifying regions, controlling the stability of the roof above the gasifying coal seam, and controlling leakage of injected air out of the process area. In-situ processes are most desirable for gassy, thick, deep coal seams with high ash contents (to aid in reducing subsidence).

(g). Low BTU Processes

The low BTU processes for coal gasification generally entail a one stage gasification without an attempt at maximizing methane production. Gas purification is needed, but not to the same extent as in high BTU processes. Methanation is not needed at all. Lurgi, FMC, Chemico (with Union Carbide), and others have developed low BTU gas processes.

The low BTU gas would be suitable as a fuel for electric power generating turbines, as a source of hydrogen for liquefaction of coal, or as a clean fuel for the heat required in a high BTU gas process.

B. Coal Liquefaction

1. General Description

Liquefaction as considered here will refer only to processes where the major final product is a hydrocarbon liquid pumpable at ambient temperatures. The advantages of liquefying coal primarily include:

-- diversity of transportation methods (e.g., truck, rail, pipeline);

-- diversity of users (e.g., homes, small industrial plants, peaking plants for the electric power industry);

-- use as a petrochemical feedstock;

-- ease of storing for future use.

This report will examine two processes, each representative of a class of liquefaction processes. The first is a low pressure, incomplete (i.e., some gas and solid product is produced along with the liquid) liquefaction, and the second is a high pressure, almost complete liquefaction process where the final product is almost primarily a liquid.

The chemical principle of liquefaction is that of cracking the carbon-carbon bonds in the large coal molecules to smaller hydrocarbons, and hydrotreating that product. This is done by heating and hydrogeneating the coal with or without the presence of a catalyst. Hydrogen may either be supplied externally or may be supplied by a partial internal gasification step.

2. The Processes

(a) COED Process (Char-Oil)

FMC Corporation has been working on a low pressure liquefaction process since 1962. The process entails introduction of crushed, dried, coal into a four-stage reactor. The coal is dried devolatilized and ultimately gasified with steam or oxygen in stage 4. The product gas from the pyrolysis unit is quenched, with the volatile organic oils being decanted and then hydrogenated to produce a synthetic crude oil. The uncondensed gas may be used as a process fuel gas. Finally, a char product is removed from the last stage of the pyrolysis-gasification system. The char may then be used as a solid fuel, or gasified to a low BTU gas for use in an electric power generating scheme.

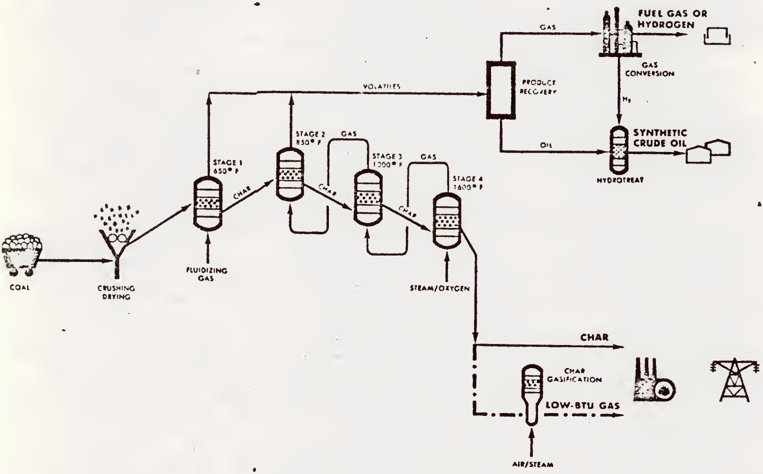
FMC claims that the overall process is 90% efficient with respect to total energy balance. This is without char gasification. When char gasification is included, the efficiency drops to 75-80%. Less than half of the total energy input would be found in the synthetic crude oil output. The remainder is in the form of char product, product gas, and process heat. Bitumous and subbituminous coals are desirable for this process, while lignite is not. See Fig. II-6.

(b) Gulf Oil Process (Solvent Refined Coal)

Gulf Oil has been developing a high pressure coal hydrogenation process which produces a synthetic crude oil. In the Gulf process, coal is introduced into a catalytic reaction vessel as an oil slurry. In that vessel the coal would be catalytically hydrogenated at 800° F under high pressure. The hydrogen would most likely come from an auxiliary gasification plant. The ash and solvent refined coal would be removed from the crude by filtration.

Fig. II-6

Schematic Flow Diagram of the FMC-COED Process*



*See Reference 28.

Lignite is the most reactive coal type and is the preferred input carbon source; however, subbituminous coals are satisfactory.

C. Electric Power Generation

1. Introduction

Coal is used to generate electrical power by the use of thermodynamic cycles. The three heat engine cycles of importance are:

-- Steam Turbines (S-T) (Rankine Cycle)
-- Gas Turbine (G-T) (Brayton Cycle)
-- Magnetohydrodynamic (MHD)

2. Rankine Cycle

In the Rankine cycle, a working fluid (usually water) is heated under pressure to a given temperature. The fluid is then allowed to expand against a piston or turbine and the work performed turns a dynamo to generate electrical energy. The efficiency of such cycles is dependent upon the initial temperature of the fluid and the final temperature measured in degrees Kelvin (defined as 273 + the centigrade temperature).[6]

$$\text{Efficiency} = \frac{\text{Tin} - \text{Tout}}{\text{Tin}}^{d}$$

Obviously, efficiency increases as Tin gets larger or Tout gets smaller. To keep Tout as small as is reasonable, the output fluid

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[d] Tin is the high temperature end of the cycle (the combustion temperature; Tout is the low temperature end of the cycle (the temperature of the gases when they exit from the turbine)

is cooled by a circulating fluid such as air or water. The working fluid will be recirculated to the boiler for further use. Typical fossil-fuel steam turbine efficiencies are in the order of 40%.

3. Brayton Cycle (Gas Turbine)

The Brayton cycle (or gas turbine) allows hot combustion gases to expand directly against a turbine to turn the dynamo. Because this process will contain water vapor, CO_2, SO_2, and some particulate matter, the turbine is subject to chemical and physical wear from these compounds. Therefore, natural gas (with minimum particulate and SO_2) is preferred over coal or oil combustion products.

4. MHD (magnetohydrodynamics)

MHD electric power generation uses the heat from the combustion of a fuel (coal, oil, gas) to propel an electrically charged gas through a channel containing electrodes. Surrounding this entire channel is a large magnet. As the charged gas expands through the channel a current is induced in the gas and may be drawn off at the electrodes to supply a direct electrical voltage source. In order to ionize the gas, a "seed" material such as potassium carbonate (K_2CO_3) is required. This material must be recovered in order to keep the operation cost of the plant reasonable.

The MHD plant would be required to run in series with either a gas or steam turbine. This is because, while the MHD generator runs at 4000-5000° F, the final gas contains much of the original combustion heat which still needs extraction in order to maximize the conversion of heat to electricity.

Table II-1 presents estimates concerning MHD combined cycle present and future efficiency considerations made by the AVCO Corporation.[7]

Table II-1

MHD Combined Cycle Efficiencies

MHD in series with	Present air preheat technology (2000° F)	Advanced air preheat technology (3000° F)
Steam turbine	50%	60%
Existing gas turbine	46%	56%
Advanced gas turbine	55%	65%

If present MHD technology were presently sufficient for commercialization, then presently existing technology would require a steam turbine in series with the MHD plant in order to maximize efficiency. However, with advanced air preheater technology and advanced gas turbines, optimum (65%) efficiency is obtained with gas turbines rather than steam turbine combined cycle.

The efficiencies listed above ideally consider the use of any fuel. However, in practice the direct combustion of coal is fraught with many difficulties not encountered when combusting gas. Such difficulties include electrode wear and deposition respectively from SO_2 and particulate matter. Another difficult problem is that of removing (for recirculation) the seed material from the post combustion products. AVCO[7] is presently investigating a combined low BTU gasification-MHD process where waste MHD heat would be used as the heat input to a gasification plant. However, work is also continuing on the direct coal conversion front.

5. Stack Gas Sulfur Scrubbing

Stack gas sulfur scrubbing is being placed in the electric generation section, because it has had its widest known publicity relative to the electric power industry. However, its application is not limited to the electric power industry, but rather to any combustion process with SO_2 as a flue gas product. SO_2 scrubbing is presently in commercial application in only a few U.S. electric power installations; however, ambient air quality concerns and State emissions standards may make scrubbers a necessity in many industries in the near future.

There are many scrubber system approaches, but only three will be discussed here.[e] They are the "throwaway" ($CaO/CaCO_3$) lime/limestone scrubber; the recyclable magnesium oxide (MgO) scrubber, and the elemental sulfur by-product "citrate" scrubber.

In the first two systems, a water slurry of either MgO or $CaO/CaCO_3$ is sprayed into the flue gases rising in the stack.

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[e] Other processes such as the catalytic oxidation system of Monsanto and UOP introduce no new environmental parameters into the discussion. Examples of a sludge producer, sulfuric acid producer, and elemental sulfur producer are included in the cited examples.

The slurry that falls down is then collected. The slurry will contain water,a sulfite and/or sulfate of either calcium or magnesium, as well as trace materials absorbed by the spray slurry. The collected slurry is then concentrated and sent either to disposal (lime/limestone) or to a regeneration facility (magnesium oxide).

Chemico presently has a magnesium oxide SO_2 scrubber in operation in a Boston Edison Plant (150 MW) in Boston. The Boston Edison operation has found removal efficiencies relatively constant at about 90%.[8] The Montana Power 720MW generating plant at Colstrip, Montana will be using a lime scrubber on its units Numbers 1 and 2 to be completed in 1975. One of the major objections precluding a positive judgment of the technical feasibility of scrubbers has been the tendency of the product materials to cause scaling. Chemico has successfully demonstrated that scaling can be avoided by judicious control of the PH (acid-base characteristics) of the circulating product material.[9]

A new scrubber concept, developed by the Bureau of Mines along with Peabody Engineering, Pfizer and Kerr McGee,[10] is the "citrate" system. This system consists of a sodium citrate solution which absorbs the SO_2 from the flue gas. Some of the absorbing solution is continually bled off and reacted with hydrogen sulfide (H_2S). That reaction creates elemental sulfur which can be purified as a saleable by-product. Ideally, the treated absorbing solution is then recycled back to the primary absorber. The H_2S reactant must be purchased or manufactured on the site.

Table II-2 sets forth comparative process conversion efficiencies.

Table II-2

Conversion Process Efficiencies

Process	Conversion Efficiency	Comment
Gasification		
HyGas	65%	Includes Conversion to high BTU gas & liquid product.
BiGas	65%	High BTU gas product only.
CO_2 Acceptor	65% - 70%	High BTU gas product only.
Synthane	60% - 65%	High BTU gas & liquid product.
Lurgi	60%	High BTU gas & liquid product.
Low BTU	80%	Low BTU gas product only.
In-situ	70%	High BTU gas product only.
Liquefaction		
FMC (COED)	75% - 90%	Higher efficiency for conversion to gas, oil, and char (solid); lower efficiency occurs when char product is gasified on-site.
Gulf	75%	This estimate includes a high BTU gasifier; efficiency would be higher for liquid and solid production only.
Electric Power Generation		
Steam Turbine	40%	
Gas Turbine	40%	Present technology.
MHD - Gas Turbine	65%	All advanced technology (See Table II-1)

D. Mining and Transportation

The generic term strip mining refers to the complete removal of overlying flora, soil and rock (overburden) in order to expose the mineral or coal seam to be mined. Strip mining is generally classified into two categories, contour mining and area mining.

In contour mining, the stripping follows the contours of a slope. Generally, a cut is made into the slope perpendicular to the horizontal of the earth. A triangular swath of overburden is removed creating a flat surface (the bench) which contains the coal. The coal is then removed from the bench and the overburden is used to regrade the vacant area.

In area mining, the surface to be stripped is generally flat. The overburden is removed by first blasting and then removing the loosened overburden with large crane-type shovels called draglines. Following the draglines are coal loading shovels,which pick up the coal and load it onto trucks for haulage to a preparation site for subsequent slurry pipelining,rail transit, or mine mouth conversion. The overburden is placed in piles to one side of the excavated trench. The piles are referred to as spoil banks or spoil piles. In some cases, the topsoil layer is scraped and segregated from the remaining overburden in order to be used later in the reclamation process.

The major methods for long distance transport of coal are rail and slurry pipeline. Railroad spurs generally join the mine with a major rail line. However, unit trains, dedicated to coal transport on a closed loop (mine to power plant), have come into use in the West. Recently, coal has begun to be transported through pipelines in a slurry (pulverized coal and water mixture) form. Coal from Black Mesa, Arizona is presently transported to the Navajo generation plant in that form.

III. MANPOWER REQUIREMENTS

In determining the manpower requirements for a process, it is necessary to know the energy output of the process in order to get a labor force/energy output comparison. However, such a formulation is not strictly applicable, because certain processes have minimum energy output requirements in order to be economically feasible. In other words, it is possible to compare the manpower/unit energy output for electric generating plants with a gasification plant, but it must be recognized that a gasification plant should have a minimum 250 billion BTU/day output (for economic viability) and hence a fixed labor force, where an electric generating plant output may very from a few megawatts capacity to 10,000 megawatts, and still be viable economically. Therefore, although such comparisons can give a good idea of the manpower intensiveness of the process per energy output, they cannot adequately yield knowledge of the labor force concentration required for each process. The analysis presented here will treat the problem in both ways (i.e., giving a manpower/BTU figure as well as optimum plant sizes) to give an idea of manpower concentration effects. Furthermore, processes will be separated in such a way that numerical values associated with each process parameter may be added directly to yield the value for a combination of processes, e.g., mining + electric power + SO_2 scrubbing

A. Construction Phase

1. Gasification

The standard size for a high BTU coal gasification plant appears to be 250 million SCF/day (250 billion BTU/day). Therefore, all manpower needs will refer to that baseline.

Consolidation Coal[11] expects a three year construction period for its CO_2 Acceptor Process, starting with about a 200-man construction crew, rising to a peak of about 2000 in the second year and falling off at the same rate until completion (see Fig. III-1). Bituminous Coal Research (BCR)[12] estimates a 3-4 year construction period following a pattern similar to Fig. III-1. Institute of Gas Technology (IGT) estimates[13] a 4 year construction period for its HyGas process; however, it estimates its peak construction crew size at only 1400. The crew size growth would follow the same pattern as in Fig. III-1. The Bureau of Mines estimates a construction period of 3-4 years for its synthane process with a peak construction crew reaching 2000 with a pattern similar to Fig. III-1. El Paso Natural Gas is assuming a 3 year construction period for its plant on the Navajo reservation.[14] The peak force size would be about 3000 and follow a growth pattern shown in Fig. III-2.

The in-situ processes are difficult to break down in terms of construction time and labor for constructing the surface hardware and for implementing the necessary drilling and blasting operations. It will be assumed that surface hardware will be similar to a low BTU or high BTU process excluding the coal preparation and

Construction Force Size Variation Over Time

Fig. III-1

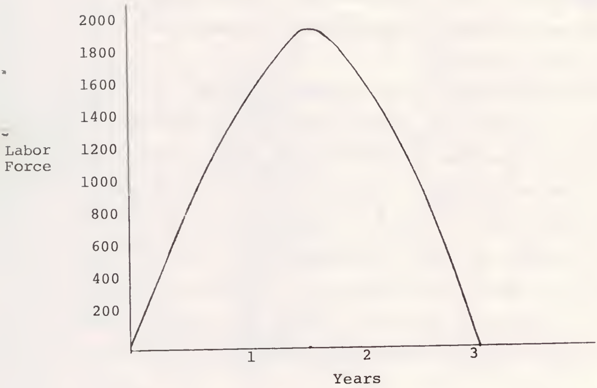
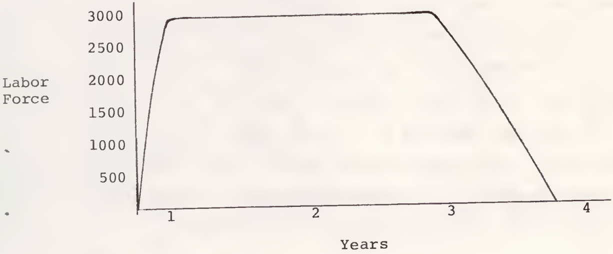


Fig. III-2



gasifier. However, the gas purification steps (and methanator if required) will be the same. After separating the drilling and coal seam preparation effort from the surface construction time, it is assumed that about 2 years and 1000-1500 men will be required to construct an in-situ facility.

A low BTU gasification plant to supply fuel gas to a gas turbine operated electrical generating plant has been proposed to OCR by Chemico[15] for the Montana Power generating station in Billings, Montana. In order to scale such a system up to the low BTU equivalent of a 250 million SCF/day output high BTU system, a construction time of about 3 years and a peak construction force of about 3600 would be required. However, economics do not require such plants to be very large. A realistic 900 MW power plant fuel gas plant would require a peak labor force of about 1500 workers over a 3 year period.

2. Liquefaction

Liquefaction processes have construction times and labor needs similar to oil refineries of similar sizes. FMC's process would require 4 years for completion (a 160 million BTU output of gas, oil and char). The process would turn out 18,000 barrels of synthetic crude per day. FMC did not have a specific construction manpower breakdown. Gulf's liquefaction process would be optimized at 100,000 barrels per day. The construction time and peak labor force are about 4 years and about 6000 people, respectively.

3. Electric Power Generation

Construction times and labor forces for electric power plants will vary depending on whether the plant is coal or gas fired and whether it uses steam, gas turbine, and/or MHD generation.

If the plant requires a scrubbing unit (only for coal or high sulfur oil-fired steam plants), an additional construction force of 200 workers is required.

4. Mining and Transport

The construction phase for a large strip mine (5-10 million tons/year) is about 2 years with a peak labor force (at 12 months) of 200 workers. The rail and pipeline transport labor forces will not be concentrated in any one location for any great length of time as they must move along to follow the progress of the line.

Table III-1 summarizes the construction manpower and time requirements for the various process.

B. Operation Phase

1. Gasification

The coal gasification processes have varying operating labor force sizes. Some of the estimates given will be for processes using caking bituminous coals, thereby requiring a pretreatment operation. When using Western subbituminous coals or lignite, pretreatment will not be needed; therefore, the acutal labor force can be smaller for those processes.

The CO_2 acceptor process developed solely for lignite (therefore, pretreatment is a priori excluded) will require a labor

Table III-1

Construction Manpower and Time Elements for Various Process Facilities

Process	Construction Time (Years)	Construction Time (years) per 100 billion BTU/day output	Peak Construction Labor Force	Peak Labor Force per 100 billion BTU/day output
Gasification (250 billion BTU/day)				
CO_2 Acceptor	3	1.2	2000	800
Synthane	4	1.6	1400	560
Low BTU (Chemico) for electric power for a 900 MW power plant	3	1.2	1500	1086
HyGas	4	1.6	1400	560
BiGas	4	1.6	2000	800
In-Situ	2	.72	1250	455
Lurgi	3	1.2	3000	1200
Liquefaction				
FMC (18,000 661/day)	4	N/A	N/A	N/A
Gulf (100,000 661/day	N/A	N/A	N/A	N/A
Electrical Power (1000 MW)				
Steam Gasification (Coal)	3	6	1800	3000
Coal with Scrubber	4	8	2000	3333
Gas Fired (Turbine or Steam)	3	6	1800	3000
MHD (CT or ST)	3	4	1800	2000
Mine (425 billion BTU/day)	2	.5	200	47
Rail/Pipeline	N/A	N/A	N/A	N/A

*N/A - Not Available.

force (operating over 2 shifts) of 520 operating and maintenance (O & M) personnel[11] with about 40 professional and clerical (P & C) workers for a total of 560 workers. BCR[12] estimates a 4 shift O & M force of about 678 with 32 P & C workers for a total of 710 workers for its BiGas process. This number includes a pretreatment force not needed for Western coal gasification. IGT estimates an operating force of 420 O & M personnel and 120 P & C people for a total of 540 (including pre-treatment) for its HyGas process. The synthane process will utilize a total of 550 (including pretreatment) workers. El Paso Natural Gas estimates that it will require an O & M force of about 900 workers for its Lurgi process. The large number of fixed bed reactors (and therefore operators) needed to attain the same coal throughput as with one fluidized or entrained bed reactor is the primary reason for this large operating force. Chemico estimates that it will need an O & M force of between 90-120 workers per shift or 360-480 (estimate will be 420) workers per day to operate a low BTU gasification plant to supply a 900 megawatt electric generating facility (assuming a 40% electric utility conversion efficiency). An in-situ plant would need about 70 drill crew operators and between 200-300 O & M workers for the surface oxygen, water, and gas purification operations for a 270 million SCF/day plant.

2. Liquefaction

Manpower for coal liquefaction operations will vary due to the nature of the plant, i.e. whether it produces only a syncrude for further refining elsewhere or whether refining is to be done on the premises. For purposes of this study, it is assumed that the final liquid product is an unrefined syncrude. FMC estimates that its 18,000 barrel/day COED process would require about 450 workers. Gulf's process which is optimized for a 100,000 barrel/day plant would require about a 1200-man O & M force.[31]

3. Electric Power Generation

Electric generating plants will vary in operating force depending upon whether they have steam turbines, gas turbines, or MHD generators, and whether they are coal, oil or gas fired. The differences occur mainly in the fuel handling and preparation systems, which are more labor-intensive for coal than oil, and more so for oil than gas. Steam turbines generally tend to be more labor intensive than gas turbines for which no large cooling system or boiler operation is needed.

Unlike other processes discussed, electric power plants can be run economically with low or high energy outputs, i.e., there is no "typical" plant size. However for the sake of this analysis, "typical" plants will be about 1000 MW. This relatively large plant size has been chosen so as to consider power for export out of the region rather than small plants designed to serve local areas only. Although gas turbines presently serve as "peak load" small power systems, it is expected that in the late 1970's units may be developed in the 200-500 MW range for use in 1000 MW generating stations.[34] Typical coal-fired steam plants use about 150-250 workers,[45] and 1000 MW gas-fired steam plants use 50-100. Gas turbine steam plants scaled up to 1000 MW would use about 40-70 workers.

When considering an MHD plant, a determination must be made whether coal or low BTU gas would be used. In the event of direct coal usage, 150-250 operators would be needed for a combined cycle MHD-steam plant. If a gas-fired MHD plant were used, then the MHD-steam plant would require 75 and an MHD-gas turbine plant would require 50.

In any case, when using low BTU gas derived from coal, the consolidated operating force (including the gasification operating force) must be considered if they are on the same site. However, because the gas may be made in one area and piped up to 200 miles,[f] the operations are not immediately additive with respect to a specific locale. The necessary data is available to determine the total operating force for any scenario requiring low BTU coal-derived gas used to fire an electric generating plant (gas, steam turbine, or MHD combined cycle).

The scrubber units on a power plant stack require little additional operational manpower. Chemico's Boston Edison[16] operation requires 2 people per shift (8 people per day) excluding sludge handling. They believe that about 3 workers per shift would handle a 1000 MW scrubbing unit. Similar projections can be made for the citrate process. However, the sludge handling removal, sludge fixing (if needed), and transport to final disposal can vary between

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[f] The further the low BTU gas is piped, the more rapidly its low production cost begins to lose competitiveness with high BTU gas whose transport cost is about half of the low BTU product.

5 and 25 persons[17] per shift (or a total of 20-100 workers) depending on the method of removal from settling ponds and transport (e.g., trucks are more labor intensive than pipelines). An average of 15 workers/shift (or 60 total workers) will be used for sludge handling. In processes such as the citrate, where the final product is solid elemental sulfur, the handling force should be reduced, because storage is easy and transport will be non-continuous, i.e., it will be dependent on the market demand for sulfur and thus shipments will occur only when an order has been placed for it.

4. Mining and Transport

The labor force at a surface coal mine will depend upon the width of the coal seam and the overburden depth as well as the reclamation effort to be mounted. Peabody's Big Sky operation in Montana utilizes about 82 people to mine about 4 million tons annually.[18] The Decker mine in Montana uses about 100 workers for an annual production of 4-6 million tons.[18] These values do not include business personnel, for example, bookkeepers, secretaries, receptionists or professional staff.

The 273-mile coal slurry pipeline from Black Mesa, Arizona, to the Navajo generating plant at Page, Arizona, has an operating force of about 60 workers. The pipeline has four field pumping stations, each using one man per shift. The remainder of the work force is involved in maintenance and coal preparation at the mine.

Table III-2 summarizes the operational manpower requirements for the various processes.

Table III-2

Operating Manpower for Typical Facilities

Process	BTU Output	Operating Manpower	Operating Manpower per 100 Billion BTU/day Output
High BTU Coal Gasification			
CO_2 Acceptor	250 million SCF/day	560	224
HyGas	"	540	216
BiGas	"	672	269
Synthane	"		
Lurgi	"	900	360
Low BTU Gasification			
Chemico	For powering a 900MW gas-fired steam electric generating plant (40% efficient)	420	168
Liquefaction			
Gulf	100,000 bbl syncrude/day	1200	182*
FMC	18,000 bbl syncrude/day	450	351*
Electric Power Generation			
Coal (steam)	1000 MW	150-250	250-417
Gas (steam)	1000 MW	50-100	83-166
Gas Turbine (GT)	Advanced Technology 1000 MW Capacity	40-70	47-82
MHD-Steam (coal)	Advanced Technology 1000 MW Capacity	150-250	167-278
MHD-GT	Advanced Technology 1000 MW Capacity	50	56
SO_2 Scrubber			
Throwaway	Limestone for a 1000 MW system	50	83
Citrate		20	33

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*The only output considered is oil, not char, gas, or solvent refined coal.

IV. WATER USE

A. Introduction

The issue of process water use is quite complicated, and only in certain areas can absolute figures be generated. However, good "ballpark" estimates for process water use are available and will be discussed. Furthermore, the nature of that use can be evaluated to ascertain whether the figures given represent absolutely necessary use or optional use, (e.g., water going into gasification to supply process hydrogen is an absolute use, while cooling water needs may vary depending on the nature of the cooling system employed). The processes will be discussed in such a manner that their water requirements will be broken down qualitatively and quantitatively. This section will focus on make-up water requirements which incrementally augment used or "lost" water.

B. Gasification

In general, water may be needed in the following areas in gasification processes.

1) As a source of chemical hydrogen to produce methane;

2) Slurry preparation for coal feeding;

3) As steam to run the gas compressors or electric power turbines;

4) As a quench for ash or slag and as a treatment for coal dust control;

5) As a solvent medium in the gas purification steps;

6) As a coolant for the gasification step, gas cooling step, methanation step, and steam condensation.

1. Water for Hydrogen

All of the high BTU processes will use approximately the same amount of water for hydrogen production because the ultimate methane production reactions are the same for any given type of coal. (These reactions have been discussed in Chapter II.) Because of the reaction rate differences, however, each process will use a different steam-to-coal ratio in the gasification step. The unreacted steam is later regained as contaminated water when the product gas is cooled. The initial process water input varies between 1800-4000 acre feet per year with about 1500 acre feet actually being consumed for hydrogen production. (This value is slightly dependent on the moisture content of the coal.) A typical low BTU process needs about 1/3 as much H_2 as a high BTU plant and therefore only about 1/3 as much chemical process water for similar quantities of coal to be gasified.

2. Coal Preparation

A water slurry is used in the BiGas Process to introduce coal into the gasifier. The water-to-coal ratio is one to one by weight. The slurry water is collected before the coal actually enters the gasifier and is recycled to a water holding pond. This amounts to about 4000 acre feet/year. None of the other processes uses such a water slurry.

3. Steam Production

All of the gasification processes use steam plants to supply the plant's mechanical power. The steam either drives steam engines directly or is used to generate electricity which then operates electric motors to do the work. The power is required to pump water, move coal, compress high pressure process steam to drive the air compressors needed to separate oxygen from air in all high BTU processes except the CO_2 Acceptor & HyGas electrothermal. Pure oxygen is required for combustion in all of the high BTU processes except the CO_2 Accepter and HyGas Electrothermal processes. The steam plants vary in rated capacity from about 90-150 MW. The HyGas Electrothermal process requires a 400 megawatt electrical power plant for generating both process heat and mechanical power. The blowdown water from the steam production boilers is not considered "lost" because it goes to the ash quench; however, there are evaporation losses of between 500-1500 acre feet/year depending on the pressure rating, size, and construction of the boiler and its connecting shafts.

4. Quench Water

Ash quench water is used for all of the high BTU processes (except in-situ). The amount of quench water lost due to evaporation and ash disposal is strongly dependent on three factors:

1) the quantity of ash in the coal;

2) the energy value of the coal (low energy value means greater coal throughput, which means more ash);

3) the ash temperature entering the quench system.

El Paso Natural Gas Company[19] estimates that for a 20% ash, 8700 BTU/lb. coal, its Lurgi process will have a quench water evaporative loss of about 250 acre feet/year, and an additional loss due to ash disposal of about 350 acre feet/year. On the other hand, if 6000

BTU/lb lignite with a 30% ash content were to be gasified, then about 545 and 760 acre feet/year would be lost from quench evaporation and ash disposal, respectively. This means that a total of 705 additional acre feet per year of water would be consumed for ash quenching in that same Lurgi process because of coal differences.

Ash temperatures will determine quench water evaporation rates. In some processes char rather than ash is the solid gasifer product. The char is later combusted to yield process heat with ash being produced at that point. Only the BiGas process uses process temperatures in which ash leaves the gasifier as a slag (molten ash) at about 2700°F. When the slag hardens (after quenching), it will be in a glassy state and thus be much less porous than the quenched ash of the other processes; therefore, less water will be lost when the ash is removed from the quench tank for final disposal. However, due to its high temperature more water will be lost to ash quench evaporation than in the other processes.

5. Gas purification

After ammonia is stripped from the product gas, it is dissolved in aqueous solution for storage and ultimate disposal (sale). El Paso's Lurgi process[20] will produce about 400 acre feet of ammonia solution per year of which about 75% or more will be water. This means that the water use from this step will amount to greater than 300 acre feet/year. Other processes will differ with respect to ammonia production and therefore with respect to solvation water required to remove and store the ammonia. Low

BTU gas production may not require ammonia removal in order to meet product gas specifications, and therefore that water requirement may not exist for such processes.

6. Cooling Water

Cooling water is required for the following purposes:

a. Gas Cooling

After gasification and the shift reaction, the product gas is cooled to condense out unreacted water, oils, salts, and ammonia; the quantity of cooling needed is dependent on the quantity of unreacted steam and the quantity of organics produced. This in turn is dependent on the specific process kinetics dictating the ratio of water to coal in the reaction. The heated cooling water used here has little value as power steam and is used strictly for cooling. In-situ processes may need little gas cooling because the gas will cool to some degree as it expands at least 700 feet upward from the coal seam to the surface plant.[g]

b. Methanation Cooling

Because the methanation reaction (discussed in Chapter II) is highly exothermic, its temperature must be kept rather low in order to maintain a high methane yield. This means that a great deal of heat must be removed by a coolant. The cooling water used here is of high enough temperature to be recycled for subsequent use as boiler feedwater for power steam production, and will therefore not go to a cooling tower.

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[g] In-situ processes will be used primarily for coal seams at depths greater than 700 feet.

c. Power Cycle Cooling

If the plant's mechanical power is supplied either by steam engines, a steam turbine electric generation unit, or a combination of both, then cooling is essential in condensing the spent steam for reuse. In the unique case where the gasification process heat is generated electrothermally (HyGas electrothermal), then additional power plant cooling is required over and above that used in other processes.

Because most of the high BTU processes have similar overall energy efficiencies (about 60%-65% conversion), the non-output 35%-40% energy has either gone into endothermic reaction heat, mechanical power for compression, or to the atmosphere. The processes which require high reaction pressures and much solids movement also require more mechanical power than the others, and subsequently greater cooling of steam turbines for mechanical or electrical power plants. Also, the number of gasifier units per plant, and the subsequent gas and solids movement in these units will play a role in plant mechanical power needs (Lurgi may have as much as 20 times as many gasifier units per plant as the other processes).

Approximate steam and steam-electric auxiliary power plant power output ratings for some of the processes are as follows:

Processes	Mechanical Work (MW)
El Paso Lurgi	140
HyGas (Oxygen)	115
HyGas (Electrothermal)	400
CO_2 Acceptor	100-200
In-Situ (Excluding drilling power)	80

C. Liquefaction

The uses of water in liquefying coal are qualitatively similar to the uses in gasification; however, the quantities are different. The differences exist in the following areas:

1. Chemical hydrogen

When coal is liquefied, the final carbon-to-hydrogen (C:H) ratio is about 1:2 (the coal itself has a 1:1 C:H ratio), while in high BTU gasification this ratio is 1:4 (see chapter II). This means that an external hydrogen source supplies one unit of hydrogen in liquefaction for every 3 units needed in high BTU gasification. This hydrogen is derived from water. A general rule of thumb might be that a liquefaction plant requires about 1/3 as much chemical process hydrogen as a high BTU gasification plant (and the same as a low BTU process) per unit of coal processed.

2. Steam production

Steam production for mechanical and electrical power will be needed in liquefaction plants as in high BTU gasification plants, but probably to a smaller degree because no oxygen plant is required.

3. Ash quench

In the FMC COED process, a final ash is not obtained in the liquefaction production train. The final solid product is char, which will not be water quenched. However, ash will be produced when the char (or raw coal) is gasified and/or combusted to produce process hydrogen and heat, respectively, so that approximately the same amount of quenching would be needed as in gasification processes.

In the Gulf process, a quenchable ash will be derived from an external gasifier producing hydrogen, but the ash and solvent refined coal generated in the liquefaction chamber will be filtered into a cake and will probably not be water quenched. This would mean up to 1/3 less quench water is needed than for high BTU gasification processes per unit of coal processed.

4. Gas purification

The FMC system uses a water quench to condense the product liquid. Hydrocarbon oils are then decanted from the system. Included in the aqueous phase, however, would be ammonia (NH_3), hydrogen cyanide (HCN), and hydrogen sulfide (H_2S). Because of these impurities a continual 5% bleedoff is required. The remainder of that water is recycled for further use in the quench system.

The Gulf system uses no water quench, but will need to absorb ammonia from the gas product above the oil product. This ammonia will be disposed of (sold or incinerated or chemically converted on site) in aqueous solution. However, because the amount of chemical hydrogen required in the liquefaction process is lower than in the gasification process, less ammonia should be produced thereby requiring less water-absorbing solution for disposal.

5. Cooling Water

(a) Gas Cooling

As in gasification, the pyrolysis product will have to be cooled to condense the hydrocarbon vapors to the liquid phase. The FMC process actually uses a water quench spray to cool the product. The aqueous phase is separated from the product hydrocarbon liquid and is recycled with a small bleedoff and subsequent makeup is required. The Gulf process would most probably use a water cooling jacket to cool the product leaving the pyrolysis-hydrogenation area. As the peak temperature is only 800° F, not as much cooling is required as in gasification cooling. Furthermore, because no highly temperature-sensitive exothermic methanation reaction exists, no additional cooling of that nature is required.

(b) Power plant cooling

Electric power and steam power will be produced on site, and these plants will require cooling just as in the gasification reactions (but probably to a lesser degree due to the reduced power needs because of the absence of an oxygen plant).

D. Electric Power Generation

The major uses of water in electric power generation are for ash quench, as a working fluid (steam), and as a coolant.

1. Ash Quench

Electric power plants require a bottom ash quench and perhaps a spray water treatment to wet down fly ash captured during electostatic precipitation (except for gas turbines burning gas rather than coal). The Four Corners Plant in New Mexico (about 2100

MW capacity) using approximately 8000 BTU/lb. coal with about 11% ash uses an estimated 25% of its 36,000 acre feet/year water consumption on ash quench, treatment, and disposal.[21] However, 75% of that ash is fly ash requiring considerable treatment to reduce fugitive dust, and allow for easy compaction upon disposal. The ash characteristics (percentage of bottom ash, characteristics of agglomeration, etc.) will be very dependent on the nature of the coal and on the type and temperature of the combustion taking place.

The operation of wetting fly ash is quite water intensive in that the idea is not merely to cool via heat exchange, but to use the water as an agglomerating agent in the ash for compaction and subsequent easy disposal. This means that all of the water used will be lost to any further plant use.

The bottom ash:fly ash ratio must be calculated on a coal-by-coal and combustion-process-by-combustion-process basis. However, it would be fair to estimate that a 1000 MW coal fired plant would use between 1000 and 10,000 acre-feet per year depending on the coal, its ash content, and the bottom ash:fly ash ratio. The extreme high use situation would be expected for a 30% ash coal with the same bottom ash:fly ash ratio as found at Four Corners (assuming use of approximately 2 lbs of water for every pound of fly ash removed from the precipitators). The low end of the spectrum would be met with a 10% ash coal having 90% or more of its ash coming out as bottom ash. If the conditions in the combustor were such that the ash was in a slagging (molten) state, the latter conditions could quite possibly be achieved.

Steam plants and MHD plants fired directly from coal combustion will have to contend with both bottom ash and fly ash. One cannot generalize about the distribution and quantities of ash as those parameters are too process- and coal-type specific. On the other hand, gas turbine plants (which must run on non-particulate containing gas, cannot at present, nor in the near future will they be able to, be directly fired by coal[22] due to the corrosivity of the particulates and acid gases emanating from the combustion process. Therefore, there is no ash treatment problem in gas turbine operation. However, if gas was used to fire a steam electric or MHD plant, there would also be no ash quench or fly ash wetting problem.

2. Water for working fluid steam

In steam turbine operation, steam expansion performs the work to drive the generator; the steam is then cooled and condensed and returned to the boiler to produce more steam. Approximately 2% of the boiler water may be lost at various evaporation points in the cycle.[20] Another 3-5% is lost to blowdown (removal of water for removal of impurities). However, the latter may be returned as cooling water so it is not really "lost." Evaporation losses occur at the generator-turbine shaft seals and at the ejector (the device which maintains the vacuum in the low pressure condenser). A typical loss for a 1000 MW steam plant is about 6000 acre feet/year.[21]

A gas turbine plant uses the hot combustion gas directly to turn the generator; therefore, no water is required for steam working fluid.

An MHD plant using a steam turbine for a "bottoming" cycle would require about 2/3 as much water as a steam turbine by itself. However, a combined cycle MHD-gas turbine would require no water for steam.

3. Cooling water

(a) General discussion

Cooling is required for steam turbine operation in order to condense the steam at the low pressure side of the turbine, but no significant cooling is required for gas turbine or MHD-gas turbine operation. It is desirable to reduce the back pressure in steam turbines to as low a point as possible. The lower the back pressure, the higher the efficiency of the turbine, i.e., the greater the pressure drop between high and low pressure sides of the turbine, the greater the efficiency. A very desirable and practical back pressure is 1.5 inches of mercury. The greater the cooling capacity of the system, the lower the turbine back pressure will be. Because there are different methods for meeting cooling needs, each of which varies significantly in water requirements, operating back pressures, capital, operation and maintenance costs, there is no absolutely rigorous figure for cooling water needs. Due to the diversity of cooling techniques, it is important to understand the relative merits of each method. A brief discussion of cooling techniques will now follow.

(b) Cooling methods

(1) "Once Through" Cooling

This technique is the old traditional technique using the diverted river water to flow through the cooling loop with subsequent reentry into the river at a point downstream from the intake. Such a system affords inexpensive capital cost and low back pressure, but requires a large, nearby water source. It also has the environmental drawback of creating a thermal discharge problem for the river.

(2) Cooling Pond

A cooling pond is a reservoir which supplies water to the cooling system and is then returned to the pond which is itself cooled via evaporation and convection at the pond surface. Such ponds are inexpensive to construct and afford low back pressures in the turbine. However, they require considerable water use.

(3) Mechanical and Natural Draft Evaporative (Wet) Cooling Towers

This technique recycles spent cooling water through a tower where it is allowed to trickle downward in small droplets. Cooling takes place through evaporation and convection. In mechanical draft systems, air is blown across the tower by artificial means, while natural draft systems use prevailing atmospheric movement to generate air flow. These systems have greater capital requirements than the previous techniques as well as causing back pressures higher than with the other methods. Furthermore, there is an undesirable steam plume which may cause local highway or runway icing (in cold weather) as well as decreasing local visibility.

(4) Mechanical or Natural Draft (Dry) Cooling Towers

These towers are compoased of a completely sealed, closed loop system in which a coolant (possible water) circulates through the system and is cooled through conduction and convection to the atmosphere. The system must maximize the heat exchange surface to the atmosphere and must be vacuum tight using highly conductive, expensive, light weight materials. The water use may be confined to the one-time fill up of the system with water (if that is the coolant), because there is no coolant loss during operation. The system is roughly 1.5 to 5 times more costly than wet towers and 1.5 to 6 times more costly than cooling ponds in terms of capital investment. However, the back pressures are 1.3 to 5.5 times greater than those found when using wet towers. A general rule of thumb is that there is a 1% overall plant efficiency loss for each inch of mercury back pressure. This means that a system using a dry tower could have an overall plant efficiency of 34% (the worst case) compared to a system with wet cooling having an overall 40% efficiency. This would mean an operating cost increase as high as 15% (greater fuel throughput is required) over a wet cooled system to generate the same amount of power. These systems are obviously best suited to cold climates. A large dry cooled power plant (330 MW) is being constructed outside of Gillette, Wyoming[35] as an addition to the 30 MW plant already there. An additional reduction in efficiency takes place due to the need for energy intensive fans to circulate air at the cooling tower surface.

The above discussion illustrates tradeoffs between efficiency, cost, and water use when cooling is considered. Obviously, when water is abundant, the highly water-intensive, low cost systems are desirable. When water quantity is constrained, the tradeoffs must be considered in order to optimize all of the variables.

Table IV-I summarizes the cooling technology situation.

E. Sulfur Scrubbers

1. MgO and Lime/Limestone

Wet SO_2 scrubbers, such as Magnesium Oxide and Lime/Limestone systems, lose approximately one gallon of water per megawatt capacity per minute to evaporation and windage from the stack.[16,17] For a 1000 MW plant, this amounts to about 1000 gpm or about 1600 acre-feet/year. There is some additional water lost in the scrubber sludge, which is removed from the settling pond for regeneration (the MgO case) or disposal (lime/limestone case). This water might amount to 15-25% of the evaporative loss (i.e. another 250-400 acre feet/year for a 1000 MW plant).

2. Citrate Scrubber

The citrate process does not employ a solution spray; rather it employs an absorber through which the flue gasses pass. There is very little evaporative or windage loss.[10] There is no sludge (and entrained water) as the final product is dry, solid, elemental sulfur. However, there will be a continual bleedoff of absorbing solution. Whether this water will be disposed of, or can be reused is not known at present. In any event, these losses will not amount to more than a few hundred acre feet per year for a 1000 MW plant.

F. Slurry Pipeline

Pipelines used to transport a coal slurry will need approximately one pound of water for each pound of coal to be transported.[36]

Table IV-1*

Cooling System Summary (1000 MW Unit)

Type of System	Fossilfueled
Once-through	
Turbine back pressure (in. Hg)[a]	1.2-1.8
Land area (acres)	<1
Water requirement (gpm)[b]	520,000
Investment cost ($/kW)**	2-5
Cooling pond[c]	
Turbine back pressure (in. Hg)	1.5-2.0
Total area (acres)	1,000-2,000
Water requirement (gpm)	9.000
Investment cost ($/kW)**	4-10 +
Natural-draft evaporative cooling tower	
Turbine back pressure (in. Hg)	1.5-3.0
Land area (acres)	∼3.5
Water requirement (gpm)	9,000
Investment cost ($/kW)**	5-8
Forced-draft evaporative cooling tower	
Turbine back pressure (in. Hg)	1.5-3.0
Land area (acres)	∼2.5
Water requirement (gpm)	9,000
Investment cost ($/kW)**	5-8
Forced-draft dry cooling tower	
Turbine back pressure (in. Hg)	4-8
Land area (acres)	∼4-7
Water requirement (gpm)	∼0
Investment cost ($/kW)**	14-25

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*Table is from Reference 46

**Cost estimates are in 1969 dollars

[a] The units of pressure are inches of mercury (Hg)

[b] The water requirement is expressed in gallons per minute (gpm)

[c] Data are strongly dependent upon site location, topography, hydrology, and cost of land

This means that each million tons of coal transported per year would require about 800 acre feet of water. According to the operators of the Black Mesa pipeline (transporting coal slurry to the Navajo generating station at Page, Arizona), the slurry water should contain less than 100 ppm dissolved solids. A high salt content would allow some of the salts to be absorbed into the coal, thus possibly causing corrosive and scaling effects on the boiler.

G. Mining Activities

Use of water in mining is generally limited to domestic use at the mine site along with the possible need to wet down pulverized coal in order to minimize fugitive dust. There may also be a need for water in the reclamation operation (for irrigation and compaction). El Paso Natural Gas expects to use about a combined 2100 acre feet per year[20] at their mine and other sites away from the gasification plant site. They will be mining about 10 million tons of coal per year using a force of about 400 people.

H. Domestic Use

Average U.S. domestic water use (cooling, cleaning, sewage, etc.) is about 120 gallons per person per day. It is assumed that the semi-arid regions that quantity would be lower, e.g. 100 gallons per day. This amounts to about .16 acre feet per person per year for domestic water use. If there were an increment of 10,000 new individuals moving into a new industrial town, they would use about 1,600 acre feet of water per year.

Table IV-2 summarizes the water use by process category.

Table IV-2

Water Use for Conversion Processes (Acre Feet/Year)

Process	Typical Plant Size	Process Water	Cooling Water[b]	Ash, slag, or sludge control, or slurry water	Boiler Feed Water	Other	Totals	Average acre feet/year per 10^8 BTU/day output
Gasification[c]								
CO Acceptor	250 MMSCF/day (1000 BTU/SCF)	3200	0-6000	400-600	500-1500	700	4800-12000	1.9-4.8
HyGas Electro-thermal	250 MMSCF/day	2500	0-12000	400-600	2500-6000	700	6100-21800	2.4-20.7
HyGas Oxygen	250 MMSCF/day	2500	0-8000	400-600	500-1500	700	4100-13300	1.6-5.3
BiGas	250 MMSCF/day	3300	0-9000	2000-9000	500-1500	700	6500-23500	2.6-9.4
Synthane	250 MMSCF/day	3000	0-8000	400-600	500-1500	700	4600-13800	1.8-5.5
Lurgi	250 MMSCF/day	3600	0-8000	400-600	500-1500	700	5200-14400	2.1-5.8
In-situ	270 MMSCF/day	4000	0-6000	0	300-900	800	5100-11700	2.0-4.7
Low BTU	Enough to fuel a 1000 MW steam electric plant (1.52×10^{11} BTU/day)	600	0-1800	250-400	150-450	200	1200-3450	0.8-2.3
Liquefaction[c]								
FMC (COED)[f]	18,000 bbl/day (syncrude) (1.35×10^{11} BTU/day)	500	0-5000	400-600	150-450	1000	2050-7550	1.5-5.6
Gulf (SRC)[g]	120,000 bbl/day (syncrude & LPG) (6.6×10^{11} BTU)	2000-2500	0-10000	250-500	600-1600	2000	4850-16600	0.73-2.5
Electric Power Generation[a]								
Steam turbine (ST)	1000 MW (1.5×10^{11} BTU/day	- - - - -	0-15000	2000-9000	6000	200	8200-30200	13.7-50.3
Gas turbine (CT)	"	- - - - -	0	0	0	100	100	0.15
MHD-ST	"	- - - - -	0-10000	1340-6000	4000	200	5540-18200	9.2-30.3
MHD-GT	"	- - - - -	0		0	100	100	0.15
Flue Gas Scrubbing for SO_2 or particulate	in a 1000 MW plant (1.5×10^{11} BTU/day)							
Electrostatic precipitator		- - - - -	0	Included in process water above		0	0	0
Wet particulate scrubber	"	1600	0	400	0	0	2000	3.3
Lime/limestone or MgO SO_2 scrubber	"	1600	0	400	0	0	2000	3,3
Citrate SO_2 scrubber	"	400	0	0	0	0	400	0,67
Mining & Transportation								
Mining & rail	3000 tons/day (9000 BTU/lb) (1.1×10^7 tons/year)	- - -				500-2000	500-2000	.09-36
Slurry transport			8800				8800	1.63

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[a] BTU output is for major product only, i.e., high BTU gas, low BTU gas, oil, or power

[b] The range varies between entirely dry cooled and entirely wet cooled.

[c] Depends on ash and BTU content of coal. Values presented are for use of 10-20% ash, ca. 8000 BTU/lb. coal.

[d] Range is dependent on use of water resulting from slurry dewatering.

[e] Excludes all mine and scrubber water requirements.

[f] Based on use of subbituminous coal (excludes any use for gasification other than as a hydrogen producer.

[g] Based on use of bituminous coal (excludes any use for gasification other than as a hydrogen producer.

[h] Assumes advanced preheat technology allowing for a 60% cycle efficiency.

V. WATER POLLUTION

A. Introduction

In most of the conversion processes discussed there will be no aqueous outfalls (i.e. dumping of waste water into surface waters) directly from the process. The two exceptions are possibly power plant blowdown and pumped out mine pit water. The wastewaters from the gasification and liquefaction processes will either be pumped to lined evaporation ponds or incinerated. In the ponding method, water will evaporate, and the wastes will ideally, either be biologically degraded to simpler forms, be concentrated, or undergo chemical transformation with the new chemical form becoming concentrated. However, other distinct possibilities may occur. No lining is completely leak-proof, thereby allowance must be made for leaks due to physical or chemical degradation of the lining in some places. Secondly, there will always be permeation of specific components in solution due to osmotic pressure. Thirdly, if the ponds contain volatile components such as hydrogen cyanide, ammonia, phenols, or other soluble organics, these are subject to evaporation along with the water, creating an air emissions problem similar to that created when aqueous wastes are incinerated. Assuming neither leaks nor evaporation, there is still a problem remaining when the project life is finished. At that point, there is certain to be a large concentration of salts (both toxic and otherwise) which will need to be treated in such a manner as to allow the pond land to be reclaimed. Finally, there is a problem with wildlife drinking at the pond and perhaps concentrating and spreading some of the toxic metals. It is beyond the scope of this report to evaluate the properties of pond linings, including their physical and chemical stability over time, as well as their permeability properties when intact. Nor can the frequency of pond visits by birds or land mammals for drinking purposes be evaluated. That sort of analysis should, however, be included in any impact statement discussing potential ground water pollution problems due to pond leaks or osmotic flow. Furthermore, it is not in the scope of this report to discuss the evaporative emission rates of volatile components in solution in these ponds. These data, however, should be estimable from the chemical literature concerned with vapor pressures of components above solutions as a function of concentration and temperature.

This report will contain a discussion of the qualitative nature, and where available, the quantity of pollutants found in the wastewaters of the different processes. Given that starting point, the possible infiltration of pollutants into ground water systems or pollutant evaporation into the atmosphere may be explored with respect to specific hydrologic, geologic, and meteorlogic sites, as well as specific liner types and pond geometrics.

There is a potential water pollution problem from silt runoff from spoils at the mining site and from spoil leachate. Another problem arises from disposed ash leachate. There will also be problems arising from domestic waste waters emanating from the activities of the labor force. Before discussing these latter problems, the direct process wastewater problem will be reviewed.

B. Gasification Wastewater

1. Organic Constituents

In the various gasification processes, the production of hydrocarbons (of higher molecular weight than methane) is dependent on the process temperatures. These hydrocarbons arise from coal devolatization and absence of decomposition. They condense out of the gas phase after the shift reaction when the gases are cooled. Such products include coal tars, light oils, phenols, and other aromatics (e.g., quinoline, pyridine, and naphthalene) as the primary liquid hydrocarbons. When the product gas is cooled, excess water condenses out with the hydrocarbons, which creates the contaminated water. The Synthane, HyGas, Lurgi, and possibly in-situ processes will have such a wastewater problem (the hydrocarbons in the in-situ process may, however, be absorbed on the ungasified coal as they expand before reaching the surface). The CO_2 Acceptor, BiGas, and the Chemico low BTU process will not generate appreciable organics due to their high temperatures (discussed in Chapter II). Because of the economic value of these organic substances, they will be recovered as by-products to as great a degree as possible before the water is sent to the evaporation pond.

Table V-1 shows a Federal Power Commission[24] estimate for total untreated wastewater organic production using Illinois #6 coal.

Table V-1

Estimates of Organics Production from Gasification of Illinois #6 Coal

	Tons/day
Phenols[24]	10-70
Benzene	50-300
Oils and Tars	400

On the other hand, Table V-2 shows El Paso Natural Gas[20] estimates of by-product collections of organics from the Lurgi process, using New Mexico subbituminous coal.

Table V-2

Estimates of Organics Production from Lurgi Gasification of Subbituminous Coal

	Tons/day
Phenols	1352
Tar	1042
Tar oil (heavy oil)	533
Naptha (light aronatics)	240

There is a discrepancy between these sets of values which is even larger when it is realized that the former is total non-methane HC production and the latter is actual by-product recovered from the wastewater. However, the former set of values is for bituminous coal and the latter for subbituminous, which may explain the differences.

The treatment of similar wastewaters has been performed by the coking industry for many years. EPA's new Effluent Limitations Guidelines[25] for that industry show typical removal efficiencies of organics from wastewater. These results are shown in Table V-3.

Table V-3

Organics Removal Efficiencies at Different Coke Plant Sites

	1	2	3	4	Average
Phenol	99.8	99.6	73.4	99.1	93
Oil and Tar	99.1	----	80.2	99.5	93

The results in Table V-3 demonstrate that phenols and oils can be removed to the extent of 93% on the average, and can, more often than not, exceed 99% removal. Applying a conservative 99% removal efficiency to the quantities collected shown in Table V-2, the expected waste water quantities are calculated. Assuming a wastewater flow to the pond of about 1500 gallons per minute (gpm) for HyGas[13] and 900 gpm for Lurgi,[24] yearly wastewater organics are shown in Table V-4.

Table V-4

Annual Wastewater Organics

	Wastewater Production (acre feet)	Phenols (thousands of tons	Oils and Tars (Thousands of tons/year)
Lurgi	1600	5	7
Synthane*	2400	5	5-7
HyGas	2400	5	5-7
BiGas, CO Acceptor, In-situ	2400	1	—

*Assumed similar to HyGas

2. Ammonia

All of the gasification processes will produce ammonia in varying degrees. The reaction forming the ammonia is:

$$N_2 \text{ (nitrogen from the coal)} + 3H_2 \text{ (hydrogen in the gasifier)} \rightarrow 2NH_3$$

The different process temperatures and pressures will cause the reaction equilibria to be different between processes, but no general rules of thumb can be used. The value of NH_3 produced should be somewhat dependent on the type of coal gasified insofar as its nitrogen content is concerned. The FPC[24] reports that about 100-150 tons of ammonia per day will be present in untreated wastewater from gasifying Illinois #6 coal. El Paso estimates[20] that 257 tons of ammonia will be collected daily as by-product from gasifying New Mexico subbituminous. Again, these discrepancies could be based on coal differences.

The EPA effluent guidelines[25] report the following NH_3 removal percentages for the coking industry.

Table V-5

Ammonia Removal Efficiencies for Coke Plants

Site	1	2	3	4	5
Percentage	44.6	28.3	92.9	95.3	39.7

The low removal values were for treatment systems that consisted merely of simple or biologically active settling ponds. The high removal efficiencies were for plants which used modern ammonia recovery apparatus. It is to be assumed that because ammonia has some economic worth, its recovery will be maximized, and that a 95% removal efficiency can be obtained. The yearly quantity of NH_3 going to the evaporation pond from a Lurgi gasification plant would be about 4900 tons/year. Because the other processes generally operate at higher temperatures and pressures, ammonia formation is enhanced,[24] but the percentage increase is not yet known with any accuracy.

3. Hydrogen Cyanide

Hydrogen cyanide production in gasification results as a secondary product from the reaction between ammonia and coal (carbon), i.e. $NH_3 + C \rightarrow H_2 + HCN$. The reaction is favored by high pressures, temperatures, and long contact time, and is diminished by high steam partial pressures. None of the former conditions are present in the Lurgi process, but the latter condition is present, thereby rationalizing the fact that HCN production has yet to be measured in the Lurgi process.[24] However, because the theoretical conditions in the other processes are more favorable to HCN production and the fact that HCN is found, in fact, in coal carbonizing processes,[1] it is expected that the other high pressure gasification reactions will produce some HCN. The quantity produced is related to the quantity of ammonia produced, and is expected to be about one percent (by weight) of the ammonia production. This would mean that about 500 tons of HCN could be produced annually from non-Lurgi processes. At present, there is little technology available to separate the HCN from the ammonia water stream. If it is assumed that the HCN is removed from the wastewater with the ammonia to the same extent, i.e. 95%, it would mean that about 25 tons of HCN per year would enter the evaporation pond for all the processes except Lurgi.

4. Common Salts and Trace Metals

Certain fractions of the inorganic ash content are volatile, e.g., mercury has a considerable vapor pressure at room temperature (and one atmosphere pressure). Most mercury (Hg), arsenic (As) and selenium (Se) compounds boil (at one atmosphere) below 1200° F.[26] That means that almost all of the gasification processes will have mercury, selenium, arsenic, and fluorine compounds coming out with the product gas stream and condensing into the aqueous phase. Because the concentrations of these substances will be very low, they should be completely soluble in the aqueous condensate of the cooled product gas.

Common salts of sodium (Na), for example, sodium chloride (NaCl), boil at about 2500° F. Although these temperatures are not reached in gasification, NaCl would have a considerable vapor pressure and would volatilize to a considerable degree at 1800-1900° F. It would be expected, therefore, that NaCl would be found in the water condensate of the BiGas, CO_2 Acceptor, Chemico, low BTU, and HyGas processes.

Of critical importance in determining the quantities of these compounds in the wastewater is their initial concentration in the input coal. To date, there has been only cursory analysis of the inorganic fraction of coals in the U.S. A very recent compilation of trace element analyses performed on U.S. coals was done by Esso Research and Engineering for the U.S. EPA.[27] The general results of that study with respect to knowledge of trace metals in coal indicate:

1) great local variation of certain elements even within a coal bed;

2) inadequate measurement techniques;

3) very little known about the fate or form of trace elements leaving the ash for the vapor phase.

However, some general ranges of trace metals for Northern Great Plains regional coal beds are shown in Table V-6.

Table V-6

Trace Elements in Western Coals

Element	ppm in coal	Comment
Beryllium (Be)	1-3.9	
Fluorine (F)	60-70	
Arsenic (As)	N/A	It generally shows up in large localized concentrations within a coal bed.
Selenium (Se)	N/A	Little data anywhere.
Cadmium (Cd)	N/A	Little data anywhere.
Mercury (Hg)	.07-.09	Consistent for Montana. N/A for North Dakota
	.03-.06	Consistent for Wyoming
Lead (Pb)	7	
Sodium (Na) (weight percent on ash)	2.9	In CO_2 Acceptor, BiGas HyGas and Chemico low BTU process.

N/A Not available

The quantity of these substances in any given coal deposit can be known with certainty only if each extracted sample is thoroughly analyzed. However, if it is assumed that the coal used in each process may vary between 20,000 and 30,000 tons/day (based on BTU content of the coal) and the above concentration ranges represent a reasonable approximation to the actual metals content in the Old West Region coals, then Table V-7 gives the ranges of the amounts of each element going into the wastewater annually (assuming no treatment for these elements).

Table V-7

Trace Elements in Gasification Wastewaters

Element	Tons to wastewater annually	
	Least case	Worst case
Be	.73	4.27
F	438	767
As	N/A	N/A
Se	N/A	N/A
Cd	N/A	N/A
Hg	.51	.98
Pb	51	77
Na	21,170	95,265

N/A (Not available)

There are four other areas where aqueous effluents may be generated in a gasification complex.

(a) Coal Pile Runoff (no problem in in-situ processes)

(b) Ash Quench Water (no problem in in-situ processes)

(c) Cooling Tower and Steam Boiler Blowdown.

Coal Pile Runoff is inherent in all coal mining and conversion processes and will be discussed under mining activities. Cooling tower blowdown water will probably go to the ash quench operation before arriving at the evaporation pond. This water will contain some anti-algal chemicals (e.g., chlorine), as well as concentrated salts from the original intake water, the quantities of which are not easily estimable. Boiler water blowdown will also contain some salts from corrosion products in the boiler as well as some phosphate compounds used as anti-corrosion compounds. The quantities involved here are quite small. Finally, the quantity of leachate from buried ash will be dependent on the method and site of the ash disposal, as well as the ash composition and the pH of the local ground waters. However, the As, Hg, Be, F, Se, and Pb (but not Cd, Ni, Zn, Mb) will probably have already been deleted from the ash in the gasification process. Sodium and potassium (nitrates, chlorides) salts will remain in the ash from the Lurgi and Synthane processes, and would be readily soluble if contacted with water. This could have marked effects on ground water salinity.

C. Liquefaction

1. Introduction

Both the COED (FMC) and Gulf Solvent Refined Coal (SRC) processes use gasification to produce process hydrogen and a gaseous fuel for plant use (or as a pipeline gas product), as well as the final liquid product.

The Gulf process is currently using the BiGas process in its engineering designs for a gasification liquefaction complex. All aqueous effluents from the BiGas process can be added directly to the effluents from the Gulf Liquefaction process. The COED process will use any of a number of low BTU gasifiers for their char pyrolysis product, thus also creating additive gasification-related aqueous effluents.

In general, the liquefaction processes use heat to drive off volatiles which are condensed, with the resulting liquid being separated from the solid, unreacted char and ash by filtration. The liquid is then hydrogenerated to upgrade it to a synthetic crude.

2. Organic Effluents

In the COED process, the product hydrocarbons from pyrolysis are quenched directly by a water spray. The hydrocarbons are decanted, but some remain behind in the quench water. The quench water is recirculated with a waste stream bleedoff amounting to 5% (by weight) of the coal feed.[28] That means the annual wastewater quantity (based on a coal use of 25,000 tons/day) is about 2700 acre feet/year. The organics in this wastewater would be very similar in concentration to a typical coke-making plant. The monohydric and dihydric phenols would be dissolved in the wastewater in concentrations of about 4000 and 2000 ppm, respectively.[29] Assuming, as previously, a 99% recovery of these compounds, the total wastewater would contain 18.3 tons of phenol and 9.2 of tar acids per year.

3. Ammonia and Cyanides

Aside from the coking industry, there is little data on ammonia and cyanide production in the liquefaction process. However, using coke industry data[29], the COED process (25,000 tons/year) would put at least 1370 tons of ammonia into wastewater (using a 95% removal rate as by-product as previously discussed). This would represent only the fraction from the pyrolysis step. This represents a lower limit because it excludes additional ammonia formed when the liquid is hydrogenated. The Gulf process should make about the same amount of ammonia; however, its product is based on 70,000[30] subbituminous tons/day (for liquefaction). Furthermore, in the process, almost all of the coal is hydrogenated, giving a value for ammonia wastewater production (assuming 95% recovery of all ammonia produced) of about 6000 tons/year. All of these calculations depend to some degree upon the percentage of nitrogen in the coal, the actual coal throughput needed in the process (a function of BTU rating) and the chemical nature of nitrogen in the coal.

Due to the low pressures in the COED process, it is expected that hydrogen cyanide production would be quite limited. On the other hand, cyanides will be present in the Gulf SRC process[31] due to the high pressure and absence of steam. The actual quantities are difficult to estimate, but a figure equal to 1% of the ammonia is realistic.[29] This would amount to 60 tons of HCN to the wastewater pond per year.

4. Salts and Trace Metals

There will be little or no volitization of salts or trace metals in the liquefaction processes because of the relatively low temperatures. Furthermore, the ash will already be relatively cool and not require a water quench, thus eliminating the possibility of leaching into the quench water which goes to the wastewater pond.

5. Auxiliary Processes

As mentioned previously, the liquefaction processes will have associated gasification plants for H_2 production. However, it is not clear yet whether the gasification plant in conjection with the liquefaction plant will merely be a hydrogen generator or will be a unit capable of producing gas quantities over and above the immediate needs of the liquefaction plant. The latter method may be desirable or necessary from an economic viewpoint. Presently, FMC is considering fuel gas production for sale to a local electric utility,[28] while Gulf is considering using the BiGas process to produce a pipeline quality high BTU gas for sale outside of the production region. In order to assess the water pollution potential of a total liquefaction complex, the exact size of the auxiliary gasification plant should be known. Effluent data for that process (available from the preceding section) may then be directly added to the values determined in this section. Table V-8 summarizes the liquefaction wastewater effluents.

Table V-8

Calculated Wastewater Effluents from Coal Liquefaction (tons/year)

	COED (FMC) (25,000 tons/ day coal feed)	SRC (Gulf) (70,000 tons/day coal feed)
Phenols	247	N/A (but less than COED)
Tar acids	123	N/A (but less than COED)
Ammonia	1370	6000
Hydrogen cyanides	5	60
Salts and trace metals	----	----

N/A -- Not available

D. Electric Power Generation

Water pollution in electric power generation will be derived from ash leaching after disposal (if coal is burned directly) and from blowdown from cooling towers and steam boilers. The latter are only problems with steam generating plants but not gas turbine or MHD-gas turbine plants.

Most power plant boilers operate under high enough temperature conditions that most of the mercury, arsenic, lead, fluorine, and beryllium and sodium would have volatilized and been emitted to the atmosphere, thus relieving the problem of leaching of those particular trace elements into ground water after disposal.

Boiler water blowdown will contain calcium and sodium sulfates and phosphates. The sulfates are naturally occurring in the water and the phosphate is added as a buffer to prevent calcium sulfate and other salt deposition (scaling) in the boiler. The sodium phosphate concentrations may vary between 10-200 ppm with an average range of about 80 ppm. That solution is quite alkaline, having a pH of about 10.5-11.0.[32] Other elements in the blowdown water will include cations (positively charged ions) from the boiler walls dissolved in the boiler water. Such cations will include iron, chromium, molybdenum, manganese and nickle, depending on the nature of the steel used in the boiler. Annual blowdown water quantities represent about 3-5% of the boiler capacity.

Cooling towers also have salt concentration buildups, and some corrosion and algal growth within the system. Often, the water is chlorinated to inhibit algal formation. Cooling towers are also blown down to reduce scaling and corrosion. That blowdown quantity amounts to about 3-5% of the total cooling water flow. The blowdown water would generally go to the ash quench system before entering the wastewater system. The actual concentrations of various salts in the blowdown water will strongly depend on the nature of the salts in the feed water to cooling towers and boilers, the corrosion, scaling and biological growth inhibitors added to the water, the pH of the water, and the nature of the materials used in the cooling system and boiler.

E. SO_2 Scrubbing

When a lime/limestone or MgO scrubber is used, the final sludge product contains calcium or magnesium sulfite and sulfate, as well as entrained fly ash. The initial sludge is dewatered in successive stages with the water from the first stages being recycled. However, the water bleedoff from the last stage may contain as much as 15% dissolved solids (calcium, magnesium, sodium, potassium, sulfate, sulfite, chloride, and bicarbonate ions). The quantity of such wastewater is dependent on the sulfur and ash content of the coal, the plant power capacity, and the efficiency of the electrostatic precipitator upstream from the sulfur scrubber. However, one estimate for 9000 BTU/lb., 7% sulfur, 10% ash Western coal is about 160 tons of 15% dissolved solids wastewater per megawatt per year.[17] For a one thousand megawatt plant, this amounts to about 130 acre feet/year of 15% dissolved solids to wastewater or 160,000 tons of soluble salts (generally non-toxic) to wastewater per year from the scrubbing system.

F. Strip Mining

The three major potential areas of water pollution from the strip mining of coal are (a) sediment runoff into surface waters, (b) leaching of exposed spoils and unreclaimed ground, and (c) contaminated ground water collecting in the pit and requiring disposal.

One estimate is that 1810 tons of sediment are eroded from the pit perimeter per million tons of coal extracted.[33] However, such an estimate can only be considered a "ballpark" figure, because erosion is dependent on the quantity and duration of rainfall, land slope, rapidity of revegetation, and nature or the overburden soil. Furthermore, predicting such a value is meaningless unless the deposition profile of the eroded sediment is known. If surface waters are nearby, then there may be a silting problem. In all probability, however, surface waters may be quite distant, and the majority of the eroded solids would deposit out before reaching a surface flow.

The spoil leaching problem has yet to be studied very extensively. However, even if salts were leached from the spoils, they would need to percolate downward to the water table in order to affect ground water quality. The high sodium soils of the Old West Region are generally quite clay-like and impermeable. It is not known whether salts leached from spoils might be reabsorbed from the very slowly downward percolating water by the soil before they reached the ground water. Some work has been done along these lines, but much more is required.[33] Some 300-400 acre feet of contaminated water might be pumped out of a coal pit annually, but this depends on the water table level and soil permeability. The contamination would probably be in terms of high pH and salinity as well as high suspended solids quantities.

G. Domestic Sewage

This report will not deal with the area of social and economic effects to geographic regions impacted by coal development. However, the increased domestic population will be a source of water pollution in terms of domestic sewage output. Average per capita daily wastewater is of the order of 100 gallons per day with a biological oxygen demand (BOD) of .6 lbs. per person per day. An increase of 5000 people into a community would increase the BOD loading to wastewater treatment by 1.1 million pounds per year in about 500 acre feet of water. If secondary sewage treatment were available the actual BOD load to surface waters would be on the order of 165 thousand pounds BOD per year (assuming 85% BOD removal).

VI. ATMOSPHERIC EMISSIONS

A. Introduction

This section will consider emissions of chemical and physical pollutants into the atmosphere. As in the water quality section, it is beyond the scope of this report to attempt to model ambient pollutant concentrations. However, this section will investigate the quantity of emissions from each identified process. The pollutants of interest are: Particulate matter, sulfur dioxide (SO_2) and trioxide (SO_3), sulfuric acid, hydrogen sulfide, nitric oxide (NO), nitrogen dioxide (NO_2), hydrocarbons (HC), trace elements, ammonia (NH_3) and hydrogen cyanide (HCN). The emissions may be from a process stack, a combustion stack, a waste pond, an incinerator, a storage tank, or from wind erosion from unconsolidated spoils or ash piles. In the case of trace elements, coal composition may be as important as the process type. In Section II of the study, there will be a discussion of the formation of secondary pollutants, such as photochemical oxidant and suspended sulfates, from directly emitted substances.

B. Gasification

Major problem areas in gasification are HC, NH_3, HCN, H_2S, SO_2, NO and particulate emissions directly from the process or its associated power plant, as well as HC, NH_3 and HCN evaporating from storage tanks, transfer operations, and evaporation ponds containing wastewater material.

1. Emissions directly from the gasification unit

(a) Ammonia and Hydrogen Cyanide

The chemical conditions in the gasifier itself are "reducing", i.e., there is an abundance of hydrogen and only small quantities of oxygen. This means that the reactions of nitrogen and sulfur will generally be with hydrogen or carbon. The resulting compounds include ammonia (NH_3), hydrogen cyanide (HCN), carbonyl sulfide (COS), hydrogen sulfide (H_2S), and carbon disulfide (CS_2). The ammonia and HCN will be removed together in aqueous solution, where the removal efficiencies are quite high (some of this, however, will be in the wastewater sent to the waste pond). The production of NH_3 and HCN is process and coal type-dependent as discussed in Chapter V. However, it is expected that there will be little NH_3 or HCN emission from the flue stack of any of the gasification processes (because these substances would probably pass through the plant in the wastewater).

(b) COS and CS_2

The gasification processes will all produce some COS and CS_2 which cannot presently be treated. Therefore, those gases will be emitted to the atmosphere. The percentage of total sulfur converted to COS and CS_2 appears to be between 1%[20] and 10%[37]. The quantity of emissions will also be dependent on the BTU content of the coal (i.e., the quantity of coal gasified), and the sulfur content of the coal. Assuming 25,000 tons of .7% sulfur are gasified each day, then about 5.5 to 55 tons of COS and CS_2 per day will be produced. If this product is incinerated, then it would be converted to SO_2 and emitted in the range of between 5.9-59 tons per day. At present, it appears that the Lurgi process converts about 1% of the sulfur, and Chemico's low BTU process converts about 10%. This area has not yet been well characterized for the other processes.

(c) H_2S

Hydrogen sulfide is the major sulfur compound produced in gasification. Ninety to ninety-nine percent of the sulfur will be H_2S. The H_2S is generally absorbed from the product gas by one of many possible solvents, and the solution is then treated to produce elemental sulfur either by the Claus or the Holmes-Stretford process. The single exception is the CO_2 Acceptor process, where, although it will produce H_2S, much of the sulfur from the coal will react with dolomite in the gasifier (see Chapter II), forming calcium sulfide (CaS). When the dolomite is returned to the regenerator for calcining, the CaS will go to the regenerator. In the regenerator, much of the CaS will be converted to calcium oxide (CaO) and SO_2, which will go to the atmosphere. Furthermore, since some dolomite is continuously bled off for disposal, it will contain some CaS which, if buried untreated, will be converted to H_2S which would permeate through the soil and be emitted to the atmosphere. Therefore, Consolidation Coal expects to treat this CaS to produce H_2S, which would go along to treatment with the primary H_2S stream from the gasifier.[11] The SO_2 leaving the regenerator will probably need to be scrubbed. It is not yet known what fraction of coal's sulfur will become CaS or H_2S, nor is it known what fraction of the CaS will become SO_2 in the regeneration. For this analysis, it is assumed that perhaps one-half of the sulfur in the regenerator will be in the form of CaS and from 1/4 to 1/2 of that will be converted to SO_2.

Processes which produce phenols and other organics will require removal of these before proceeding to CO_2 and H_2S removal; however, H_2S is partially removed in processes such as the Lurgi phenosolvan. Eventually, the H_2S will be stripped from the solution and be incinerated to SO_2. The H_2S removed in such processes will be about 3% of the total H_2S formed. The HyGas, Synthane, and Lurgi processes will need phenol removal and therefore will have this problem.

After phenols have been removed, the CO_2 and H_2S are removed from the product gas stream by a solvent. The solution is degassed and the H_2S and CO_2 are run through a process to produce elemental sulfur. The process most often used to date (in coke making plants) is the Claus process, which reacts externally produced SO_2 with the H_2S to make elemental sulfur. However, a so-called "tail gas" comes out of this process which consists primarily of excess SO_2, which is then either emitted to the atmosphere or must be scrubbed. The unreacted H_2S is generally incinerated to SO_2 before emission to the atmosphere. An English process presently gaining attention in the U.S. is the Holmes-Stretford process, which uses no SO_2 and therefore presents no tail gas problem. Furthermore, it can be used under a wider variety of CO_2:H_2S concentrations than the Claus process. The

Clause process may be considered to be about 95% efficient or better, and the Holmes-Stretford process about the same. El Paso is presently designing its Navajo gasification plant with a Holmes-Stretford plant, while Texas Eastern Transmission (WESCO) is designing its Navajo gasification plant to include a Claus sulfur plant.

(d) Hydrocarbons (HC)

In the low temperature processes (Lurgi, Synthane, HyGas,) volatile, low molecular weight (i.e., gaseous at room temperature) hydrocarbons (aside from methane) will be produced, and possibly emitted to the atmosphere or combusted for fuel. El Paso's plans[21] estimate that about 108 tons of methane, ethane, and ethylene will be emitted from their Navajo plant daily. The CO_2 Acceptor, BiGas and Chemico low BTU processes should have a smaller output of ethane and ethylene due to their higher temperatures.

Processes such as the Lurgi, Synthane, and HyGas produce tars, oils, and phenols, which will be separated from the product gas stream, collected and stored for eventual sale as by-products (the uncollected fraction will be in the wastewater as discussed in Chapter V). Atmospheric emission of these substances is likely to occur from storage tanks, wastewater separation operations, valve leakage and cooling water blowdown. The extent of these emissions will be about 8 tons per day.[41] These emissions, will contain phenols, aromatic and polynuclear aromatic hydrocarbons.

If waste ponds are used, they will contain some considerable concentration of volatile substances, including phenols, light oils, ammonia, and HCN. The concentrations of these substances are subject to evapoation and might then become emitted to the atmosphere. The quantities of such emissions would be dependent upon their concentration in solution, the ambient temperature, and the chemical reactions of the substances in solution prior to volatilization, as well as their physical-chemical characteristics in the waste pond. No simple rules of thumb can be presented to determine the extent of these emissions and their subsequent air quality impacts.

(e) Sulfur Dioxide

Sulfur dioxide is not a direct product of gasification; however, as stated previously, it can be emitted from the CO_2 Acceptor process regenerator, emitted from the Claus plant's tail gas, from incineration of the gas liquor of a phenol removal process, or from the incineration of unconverted H_2S or COS out of a Claus or Holmes-Stretford sulfur plant. The percentage of the total S converted to SO_2 will vary from 3% to 10% in all processes other than the CO_2 Acceptor, where SO_2 production may account for 20-50% of the plant's sulfur output. The actual quantity of SO_2 emitted will be strongly dependent upon the sulfur quantity in the coal, the amount of coal used, the type of H_2S cleanup used, and whether or not SO_2 scrubbers are used.

2. Auxiliary Power Plant

As mentioned in Chapter IV, all of the gasification processes require auxiliary steam and/or electric power plants. For high BTU processes, they range in size from about 90 MW to the 400 MW plant needed for the HyGas Electrothermal process. Either low BTU gas, coal or char will be used as a fuel. Utilization of low BTU gas (which must be produced from coal) is more expensive than direct use of coal, but may obviate the need for an SO_2 scrubber on the stack. If gas is used, the only emission of any significance will be NO. However, if coal is burned, then all of the problems to be discussed under the section of electric power generation will be applicable here as well.

C. Coal Liquefaction

The gaseous emissions from liquefaction plants will be very similar to gasification plants. However, there should be greater HC evaporative emissions in liquefaction, because the final product is a syncrude which will be transferred either to storage to await on-site refining (and/or transport), or will be sent directly into a pipeline for transport.

In the FMC process, only half of the sulfur goes into the gas or liquid product, while the other half remains in the char.[28] Its fate is dependent on what is done with the char, i.e., whether it is gasified or combusted on site, or whether it is shipped out as a gasification feedstock or a direct energy source for conversion processes elsewhere. Therefore, only half as much H_2S would be produced as for a gasification plant processing the same quantity of coal. In the Gulf process, most of the sulfur comes out as H_2S or COS. However, there will be residual sulfur remaining in the solid product (solvent refined coal), which will be used to fire the plant's boilers. The H_2S would be converted to sulfur either using a Claus or Holmes-Stretford process. The efficiencies of the Claus plant would probably be significantly better than in gasification, because the gas stream feed to the Claus plant would be far more concentrated in H_2S than in the gasification gas stream.[h] Therefore, it might be reasonable to assume a 98% H_2S removal capability. However, the COS that is produced will still pass through the Claus plant unconverted.

Hydrocarbon emissions from the FMC process should be similar to the gasification process, i.e., HC emissions will come from liquid product evaporative sources and emission at the sulfur plant, while the Gulf process condenses the sulfur plant vent gases in a cryogenic separator in order to collect the methane, ethane, and ethylene (LPG) as by-products.

In this analysis, it is assumed that most of the uncollected ammonia and HCN produced would be in aqueous solution, and therefore pass out in the wastewater, rather than as a gaseous stack emission. However, as stated previously, some of these substances could evaporate from the quench pond, wastewater pond, or the cooling towers.

In the FMC process, the plant heat and power will either come from the by-product low BTU gas or from the char produced as a by-product. The fuel gas would contain no sulfur, and the char would contain about half the sulfur content of the original coal (as well as only half the heating value). The Gulf process would use part of its solvent refined coal (SRC) by-product to fuel its plant.[30] This coal would contain about half of the organic sulfur originally in the coal (in western coals sulfur is found only in the organic form, unlike eastern and midwestern coals where much of it is in the inorganic pyritic form). This would mean that about 30 tons of SO_2 per day would be emitted from combustion, if the SRC were used to fuel the plant. Most of the ash is already removed from the solvent refined to coal so that there would be no fly ash emission, only carbon smoke particulates.

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[h] In the liquefaction process, the gas sent to the sulfur plant will contain less CO than in gasification processes.

D. Electrical Power Generation

1. Introduction

The primary air pollutants from electric power plants are sulfur dioxide (SO_2), sulfur trioxide (SO_3), nitrogen oxides (NO_x), fly ash, and various trace metals which may vaporize and become gaseous pollutants (e.g., mercury, beryllium, arsenic compounds, or fluorides., Other trace metals, such as nickel, zinc, cadmium, and molybdenum will exist in fly ash particles. If gas is burned, it is assumed that particulates, sulfur compounds, and trace metals will not be problems, rather only nitrogen oxides, which are formed by reaction of nitrogen (in the air) and oxygen reacting at high temperatures (over 2000° F.).

2. Coal Burning Steam Plants

All new coal burning power plants will have to meet U.S. Environmental Protection Agency New Source Performance Standards (EPA NSPS) for SO_2 and particulates, and NO_x emissions. These standards are 1.2 lbs. SO_2/M BTU heat input, .1 lbs. particulates/ M BTU heat input, and .7 lbs. NO_2/M BTU input. These are minimum federal standards and may be amended by the states in order to achieve compliance with ambient air standards. Any coal with less than .7% sulfur and having greater than 6000 BTU/lb. heating value will meet the standards. Most western coals would meet the standards without any additional treatment. However, even with these emission standards, a 1000 MW plant using a 6000 BTU/lb., .7% sulfur coal, would still emit some 176 tons of SO_2 per day,[i] which could cause ambient standards to be exceeded where air stagnation conditions might frequently be present. If such a situation existed, then SO_2 flue gas scrubbing devices would be necessary. The Bureau of Mines' citrate system and any one of a number of lime/ limestone or magnesium oxide systems might be used to obtain an 80-95% SO_2 reduction[39] from the baseline SO_2 stack emissions.

Particulate emissions will vary based on the percentage ash in the coal, the method of combustion, and the nature of the coal.

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[i] It has been assumed here that all of the sulfur in the coal has been emitted as SO_2 or SO_3, while in reality only about 95% of the sulfur is emitted as SO_2 or SO_3.[38]

A general "rule of thumb" equation for the quantity of uncontrolled particulate emissions from the following categories of coal-fired power plants is:[38]

dry bottom - 17 times the percentage ash in coal = lbs. particulate/ton coal;

wet bottom - 17 times the percentage ash in coal = lbs. particulate/ton coal;

cyclone - 2 times the percentage ash in coal = lbs. particulate/ton coal.

This means that for a 1000 MW plant (with a wet or dry bottom furnace) burning 6000 BTU/lb., using 20% ash coal, approximately 2000 tons of particulate matter would be emitted daily. Emissions from a cyclone-type furnace would be only about 1/8 of those from a regular furnace or about 250 tons/day for the power plant and coal listed above. Use of control equipment such as electrostatic precipitators, or wet scrubbers can give as high as 99.9%[38] reduction in particulates, although the actual operating efficiencies are usually between 98-99%. The wet or dry bottom furnaced power plant burning 6000 BTU/lb., 20% ash coal would need about a 96.4% reduction in particulates in order to comply with the EPA NSPS. However, NSPS compliance might not be sufficient in order to meet ambient standards. In that case, additional controls, such as an electrostatic precipitator in series with a wet scrubber may be needed in order to reduce particulate emissions to acceptable limits.

Nitrogen dioxide emissions from coal-burning power plants are about 20 lbs./ton of coal burned.[38] In order for new sources to comply with EPA's NSPS a 50% reduction in NO_2 emissions from coal-burning power plants is required. In western areas where little significant photochemical oxidant problem presently exists, these NSPS reductions may be sufficient to allow compliance with the ambient standard. However, a 1000 MW power plant would still emit some 53 tons of NO_2 daily.

Trace element emissions from coal-burning power plants will be very dependent on the quantity of the element in the coal. Furthermore the chemical nature of elements in the gas phase is not readily available. Many of the non-volatile trace elements such as zinc, nickel, cadmium, and molybdenum will be collected both in bottom ash and fly ash. Some of it will escape in uncollected fly ash. Other elements such as mercury, beryllium, fluorine, and arsenic will be in vapor form, but may be absorbed on fly ash which is captured. There are no easy rules of thumb. Table V-6 reviews what is presently known about volatile trace elements in western coal. Reference 27 contains an extensive bibliography of trace element analyses, but it too concludes that each individual coal deposit should be monitored in order to determine trace element concentrations.

One other coal related emission problem is that of benzo-(a)-pyrene (a known carcinogen). It is estimated that 600 micrograms (μg) are emitted per ton of coal burned from a dry or wet furnace and 6000 μg/ton from a cyclone furnace.[38]

3. Gas turbines and gas-fired steam electric plants

Natural gas fired power plants present no particulate, SO_2 or benzo-(a)-pyrene problem. The only emissions of concern are the nitrogen oxides, and some organic aldehydes. Presently, NO_x ($NO + NO_2$) emissions from gas-fired plants are about .39 lbs./M BTU heat input; however, EPA NSPS would only allow .2 lbs. NO_2/M BTU. This may mean as much as a 50% reduction in NO_2 emissions is required if all of the NO_x from the combustion was in the form of NO_2; however, if half were NO and half NO_2, the NSPS for NO_2 would be met. It may be possible to reduce NO_x emissions more easily with low BTU gas than with high BTU natural or synthetic gas.

As gas turbines advance technologically, combustion temperatures will continue to increase, thus generating more NO_x and increasing the need for NO_x control. NO_x emissions, however, can be virtually eliminated by combusting gas in the presence of pure oxygen, which would exclude the nitrogen reactant present in air. This may become necessary for NO_x control at very high temperatures, and due to the favorable increases in efficiency resulting from those high temperatures, it may also be economically feasible.

4. MHD (Gas turbine or Steam turbine)

In MHD generation, the critical operating parameter is high temperature, which means high NO_x concentration. At present, MHD prototypes are generating NO_x concentrations of 2200-4800 ppm.[40] However, it is believed that these concentrations may be reduced to 150 ppm.[j,7,40] Recent calculations indicate that by judicious design of the combustion chamber and flue gas exit pathway, significant NO_x reductions may become practical.[40] NO_x is the only major problem when the MHD plant fuel is gas.

When coal is used to fire an MHD plant, NO_x is still a problem, but additional problems occur from SO_2, particulate, and trace metal emissions. It is believed that the heavy fly ash particles of silica, alumina, and iron, calcium, and magnesium oxides can be removed via a cyclone operation. AVCO's theory[7] is, that after the heavy particulates are removed from the gas, sodium and potassium (both from the coal and from the MHD seed, potassium carbonate) will preferentially react with the gaseous SO_2 and SO_3 to form sodium and potassium sulfate, which can then be electrostatically precipitated. The success of the theory is quite critical to coal-fired MHD success, because it represents a potentially inexpensive and realistic method for recycling the necessary potassium seed. After collection, the potassium sulfate would be converted back to the original potassium carbonate seed via reduction and subsequent reaction with CO_2. The reduction would produce a by-product H_2S requiring conversion to elemental sulfur. This chain of events is theoretically plausible because the sodium, potassium and SO_2 concentrations, and the temperatures, would be favorable to potassium sulfate formation.

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[j] The EPA NO_2 NSPS under these conditions is equivalent to a stack concentration of 600 ppm.

However, there is very little actual experimental data to confirm these theoretical results.

E. Mining and Transport

The primary air emissions from the mining operation are particulates arising from spoil erosion and coal pulverization (if that operation is performed at the mine site). The spoil erosion rate will be dependent on the topography and wind conditions in the mining area as well as on the manner of placing the spoil, and the physical nature of the spoil itself. One estimate of spoil wind erosion is 50 tons per million tons of coal mined.[33] This value is also strongly dependent on the depth of the overburden and the thickness of the coal seam (i.e., the overburden to coal weight ratio). There will be an additional wind erosion problem from haul roads, which will require wetting in arid climates. Coal itself is quite dusty and will create a particulate problem during handling and transport. It is difficult to quantify this problem at present, but wetting the coal during the loading procedure should minimize that impact.

There will be some smoke, hydrocarbon, and NO_x emissions from the diesel equipment at the mine site, and from locomotives transporting the coal, but these will be of a very localized nature and should not significantly contribute to any area-wide ambient air problems.

F. Domestic Emissions

The labor force for any of these processes will, by driving gasoline powered vehicles, contribute HC, NO_x and carbon monoxide emissions. The emission rates are about 12 lbs. HC, 44 lbs. CO and about 7 lbs. NO_x per thousand vehicle miles traveled.[k] If for example, 5000 vehicles averaged 30 miles per day, then HC, CO, and NO_x emissions would be 1800, 6600, and 1050 lbs. per day, respectively. Finally, solid waste incinerators, if utilized will also cause CO, NO_x, HC and some particulate emissions, as will home heating units. Emissions from the latter are dependent on the fuel used, with little impact when electric heating is employed and some SO_2 and particulate problems if coal is used.

Table VI-1 summarizes the potential air emissions problem. It should be noted that Table VI-1 is based on a set of assumptions which are easily undermined. First of all, gasification and liquefaction plants may choose to power their process with gas, char, solvent refined coal, or oil which would make the numbers in the table erroneous. Also, if SO_2 scrubbers are used, the SO_2 emissions from all processes would drop considerably. It should be emphasized that by assuming use of coal as a fuel, the NO_x, SO_2 and particulate values do represent upper limits for those emissions. It should also be pointed out that if wastewater containing NH_3 and HCN is incinerated rather than treated and ponded, NO_x, NH_3, and HCN, and cyanate emissions will increase. It is emphasized that the values in the tables do not include volatilization of substances from waste ponds because such characteristics are not known to any great extent. Finally, it is not known whether untreated COS, CS_2 and H_2S will be incenerated to SO_2 or will be emitted directly after the gasification and liquefaction sulfur recovery operations.

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[k] Based on use of emission factors for a 1977 vehicle population mix.

Table VI-1

Potential Air Emissions (tons/day, Except Where Otherwise Noted)[1]

Process and Typical Plant Size	SO_2	NO_x	Particulate	Trace Elements	H_2S, COS	HCN and NH_3	HC (methane, ethane, ethylene)	HC (aromatic phenols, heavy paraffins, PNA, aldehydes)
Gasification[2]								
CO Acceptor[3,4] 250 MMSCF/day	79	4.5	3	Should arise only from power plant operation and be dependent on the trace element content of the fuel.	Assumed incinerated to SO_2	N/A	108	0
HyGas oxygen[5] 250 MMSCF/day	38	6.5	3.5				108	9
HyGas Electrothermal[6] 250 MMSCF/day	78	22.5	6				108	9
BiGas[5] 250 MMSCF/day	38	6.5	3.5				108	0
Synthane[7] 250 MMSCF/day	36	5.6	3				108	9
Lurgi[7] 250 MMSCF/day	36	5.6	3				108	9
In-Situ[4] 250 MMSCF/day	34	4.5	.5				108	N/A
Low BTU to fire a 1000 MW steam electric plant[8] (160 MMSCF/day)	16	1.7	1				30	0
Liquefaction[10]								
FMC (COED 18,000 bbl/day	13	3	1				40	10.5
Gulf (SRC) 100,000 bbl/day	36	8.5	3				20	58.0
Electric Power Generation								
Coal-fired steam turbine 1000 MW	140	56	10				1	.01
Gas-fired steam or gas turbine 1000 MW	7	16	1.5				0	.2
MHD-ST or GT (Gas-fired)	7	N/A	1				0	.1
MHD-ST (coal-fired)	N/A	N/A	N/A				1	.01
Mining and Transport (10 million tons/year)	1	.1	1.4				.1	.1
Domestic	1	7 lbs/1000 vehicle mi. + home heating + incinerators	N/A				7 lbs/1000 vehicle mi. + home heating.	.1

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[1] Assumptions: a) .7% sulfur, 10% ash, 8000 BTU/lb. coal; b) all (auxiliary) power plants are coal-fired and comply with NSPS for NO_x, SO_2, and particulates, therefore representing an upper limit.

[2] (a) Assumes H_2S conversion rate of 95%. (b) Assumes all COS and CS_2 are incinerated and converted to SO prior to emission.

[3] Half of the total sulfur goes to the regenerator and 1/4 of that sulfur is emitted as SO_2.

[4] Assumes an 80 MW auxiliary power plant.

[5] Assumes an 115 MW auxiliary power plant.

[6] Assumes a 400 MW auxiliary power plant.

[7] Assumes a 100 MW auxiliary power plant.

[8] Assumes a 30 MW auxiliary power plant.

[9] Assumes a 98-99% collection and subsequent storage of the liquid HC.

[10] Assumes a 98% H_2S conversion.

VII. SOLID WASTE

A. Introduction

Solid wastes from the processes discussed above pose indirect pollution problems. They may lead to air pollution (if incinerated), land disturbance (if buried) or water pollution problems (if leaching occurs after burial). The major solid waste problems are (1) ash (bottom ash and fly ash) from all processes, (2) SO_2 scrubber sludges, (3) spoil piles and coal cleaning residues, and (4) domestic trash and sewage sludge (if the raw sewage is treated).

B. Ash

All of the conversion processes will generate some solid residue, either a char (to be burned on site or transported), an ash, or a solvent refined coal. The BiGas process is the only gasification process producing a glass-like ash product derived from quenching a slag. The other gaisfication processes will produce a wetted coarse-grained bottom ash and some fly ash captured by a wet scrubbing system. The CO_2 Acceptor process will generate a mixture of coal ash and spent dolomite which could contain some untreated calcium sulfide capable of oxidation (after burial) to gaseous hydrogen sulfide. Approximately 2% of the dolomite is replaced continuously. The original dolomite:coal ratio is 1:10. This means that .2% of the coal feed is spent dolomite. If the coal has a 10% ash content, then spent dolomite increases the solid waste disposal problem by 2%.

The Gulf liquefaction technique will generate ash both from the liquefaction process itself and from the combustion of the solvent refined coal product for plant fuel. In the FMC process the ash remains in the char product, which may either be utilized directly at the plant site or sold as a by-product, thus eliminating the ash disposal problem at the plant site by transferring it elsewhere.

The quantity of ash in each of the processes will be dependent both on the coal feed to the process, plus the percentage ash in the coal minus the volatile ash fraction (primarily sodium chloride carbonate). Thus, a 10,000 ton per day feed of 10% ash coal will produce about 365,000 tons of ash per year.

Coal-fired electric power plants will produce approximately a 2:1 fly ash to bottom ash ratio with the fly ash requiring considerable moisture in order to prevent a particulate problem and allow compaction for easy disposal. Gas-fired plants present no ash problem.

C. SO_2 Scrubber Sludges

1. Lime/Limestone

If a lime/limestone scrubber is used to remove SO_2 from flue gases, the dry weight of the solid sludge would be four times the weight of the sulfur being scrubbed. However, in actuality, the sludge is wet and is about 1:1 water to calcium sulfate/sulfite. Therefore, the total solid waste problem is about 8 times the original weight of sulfur scrubbed.[17] To put these values in perspective, a 1000 MW coal-fired electric power plant using 10,000 tons of .7% sulfur coal per day, and achieving a 90% SO_2 reduction, would generate about 184,000 tons of sludge per year in addition to 365,000 tons of ash for which disposal is required. A gasification plant using a coal feed of 25,000 tons per day of .7% sulfur coal, and achieving 95% sulfur removal as elemental sulfur, would require scrubbing of the remaining 5% of the sulfur coming out as SO_2. This would generate about 23,000 tons of throwaway sludge per year in addition to 912,000 tons of waste ash per year.

2. Magnesium oxide (MgO) scrubber

If an MgO scrubber were used, a daily sludge production similar to the lime/limestone system would be obtained. However, that sludge would be transported to a regenerating plant to make a commercially saleable sulfuric acid by-product and a regenerated MgO for reuse. No solid waste disposal problem is created from MgO scrubbing.

3. Citrate Scrubber

The final solid product arising from the citrate scrubbing operation is elemental sulfur. This sulfur can be stored for future sale and thus creates no disposal problem.

D. Mine Spoils and Coal Cleaning Residues

During the strip mining operation, overburden is removed from above the coal seam and placed alongside the open pit. The overburden may vary between 20 and 150 feet. The volume of the overburden increases (swells) after it is removed from atop the coal seam. However, in the West, most of the coal seams are sufficiently thick (greater than 20 feet) that the expanded spoils can easily be placed back within the original pit without leaving any excess spoil requiring disposal elsewhere. Western coals are of such a nature that coal cleaning operations (leaving a residue) are generally not required.

E. Domestic Trash and Sewage Sludge

The labor force associated with the conversion or extraction operation would generate solid waste at the rate of 2000 lbs. per person per year (national average). The sewage treatment plant, using secondary treatment, would generate 2 pounds of sludge per person per year.[m] The domestic solid waste can be disposed of by landfill, incineration, or partial recycling in combination with the above methods. Sewage sludge will be disposed of either by landfill, incineration, partial conversion to a usable fuel, or will be used on land as a natural fertilizer. The choice of options depends upon trace element composition, availability of land, and public acceptance of the various methods.

Table VII-1 reviews the solid waste situation for the different processes.

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[m] That is a dry weight value. The sludge is generally only between 2-4% solids after secondary treatment and 8-15% solids after thickening. The actual quantity which must be disposed of is then 13 to 100 lbs. per person per year.

Table VII-1

Coal Conversion Process Related Solid Waste Production
(Tons/year, except where otherwise noted)

Process and Typical Plant Size	Ash[1]	Process Sludge[1]	Domestic Sewage Waste	Domestic Solid Waste
Gasification[2]				
CO_2 Acceptor 250 MMSCF/day	930,000	- - - - - -	- - - - - -	- - - -
HyGas 250 MMSCF/ day	912,000	- - - - - -	- - - - - -	- - - -
BiGas 250 MMSCF/ day	912,000	- - - - - -	- - - - - -	- - - -
Synthane 250 MMSCF/day	912,000	- - - - - -	- - - - - -	- - - -
Lurgi 250 MMSCF/ day	912,000	- - - - - -	- - - - - -	- - - -
In-Situ 250 MMSCF/ day	0	- - - - - -	- - - - - -	- - - -
Low BTU - enough to fire a 1000 MW steam electric plant (161 MSCF/ day)	547,000	- - - - - -	- - - - - -	- - - -
Liquefaction				
FMC (COED) 150,000 bbl/day	0-912,000	- - - - - -	- - - - - -	- - - -
Gulf (SRC) 100,000 bbl/day	2,555,000	- - - - - -	- - - - - -	- - - -
Electric Power Generation				
Coal-fired steam electric 1000 MW	367,000	- - - - - -	- - - - - -	- - - -
Coal-fired MHD-ST 1000 MW	245,000	- - - - - -	- - - - - -	- - - -
Gas-fired ST,GT,or MHD-ST or GT 1000 MW	0	- - - - - -	- - - - - -	- - - -
SO Scrubbing				
Lime/limestone - for a 1000 MW coal-fired steam electric plant	0	184,000	-------	- - - -
Magnesium oxide-for a 1000 MW coal-fired steam electric plant	0	- - - - - -	- - - - - -	- - - -
Citrate-for a 1000 MW coal-fired steam electric plant	0	- - - - - -	- - - - -	- - - -
Domestic	N/A	- - - - - -	13-100 lbs/ person/year	1 ton/per- son/year
Mining and transport	0	0	0	- - - -

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[1] Assumes use of a 10% ash, .7% sulfur, 8,000 BTU/lb coal.

[2] Assumes equal conversion efficiencies of 62.5%.

[3] Range depends on whether the char by-product is converted on-site or transported off-site for gasification or combustion.

[4] Depends on the fuel used for home and commerical heating.

[5] Wet weight value; dry weight is approximately half that number.

VIII. LAND USE

This chapter will only deal with the quantitative issue of land to be used for processes. The qualitative issue of land disturbances, reclamation from mining activities, and waste disposal will be treated in Section II of this study.

A. Gasification

The proposed El Paso Lurgi gasification site in New Mexico will occupy about 960 acres.[42] This is for the entire plant facility, excluding the ash disposal site, which in this case will be at the mine. The site also includes 100 acres to be used as a lined waste pond. The site also includes about 10 acres for coal storage and a gas-fired electric power plant. Other gasification facilities should occupy a somewhat smaller land area due to the fact that they require a smaller number of gasification units per plant (El Paso will be using more than 30; the others generally use about 2). Finally, although Lurgi, Synthane and HyGas produce liquid by-products requiring storage, the CO_2 Acceptor, BiGas, and low BTU by-products do not, and will therefore not require liquid storage areas. The CO_2 Acceptor and low BTU processes do not need air separation units (oxygen plants), and will therefore require still less land.

An in-situ operation will not require any coal storage or gasifier space, because the coal is gasified in place beneath the ground. However, it will need all of the other above ground facilities used in gasification.

A low-BTU operation will not require a methanation unit so that its space requirements should be lower (per BTU output) than any of the surface high BTU gasification processes.

In the above discussion, it is assumed that ash will be disposed of outside of the plant grounds; however, for completeness, ash disposal for the high BTU processes will require (except in-situ) about 680 acres.[n] The in-situ process has no ash disposal problem.

B. Liquefaction

The FMC (25,000 ton per day coal feed) process should have land needs very similar to a gasification plant. Although no oxygen plant or methanator is required, a considerably greater liquid storage area is required than for gasification. If char gasification takes place at the process site, additional land area will be needed.

The Gulf process should utilize between two and three thousand acres for its process (100,000 bbl/day), excluding an on-site high BTU gasification plant. Much of that land would be for transfer and storage facilities for the large quantities of liquid product. Again ash disposal is not included but would amount to about 680 acres for the FMC process and about 1900 acres for the Gulf process using the same assumptions as in the gasification calculation.

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[n] Assumes 25,000 tons per day 10% ash coal feed; .05 ton/ft^3 ash density, and a 20 ft. height for the ash pile aggregated over a 30 year duration.

C. Electric Power Generation

Land used for electric power plants will vary with plant capacity, but also with other factors such as ash disposal site, cooling method, fuel used, and the number of units per plant. No strict rules of thumb apply to land used for electric power plants. As an example of the inconsistency of land usage for power plants, Potomac Electric Power Company[7] uses 427 acres for its 2-unit, 1100 MW plant at Morgantown, Maryland, and uses 1000 acres for its 3-unit, 550 MW Dickerson plant.[43] The latter has room for considerable expansion, however. The values given above are for plants using the least land-intensive cooling systems ("once through"). Again, ash disposal is not included in the land use figures. However, a 1000 MW steam electric plant would require about 270 acres for ash disposal using the same assumptions as used in the gasification calculation except that 10,000 tons of coal are used per day instead of 25,000. A 1000 MW gas fired or combined MHD cycle plant would probably require less space, because no cooling plant or coal storage area would be required. Furthermore, the MHD systems, even using coal, would require 50% less ash disposal space than a 100% coal-fired steam electric plant due to its higher efficiency. The all-gas systems would require no ash disposal area.

D. SO_2 Scrubbers

Sulfur dioxide scrubbers themselves use very little additional space around a coal conversion plant; however, their final products may need considerable land for disposal.

The lime/limestone process produces a sludge requiring disposal in a lined pit. A lime SO_2 removal scrubber on a 1000 MW power plant operating at 90% efficiency will generate 1647 acre-feet of dry sludge or 3698 acre-feet of wet sludge over a 30-year period.[o] A limestone scrubber would generate 2043 of dry, or 4644 acre-feet of wet, sludge over a 30-year period. If the sludge pond were 15 feet deep, this would mean that the land required for dry and wet lime, and dry and wet limestone sludges would be 110, 247, 136, and 310 acres, respectively. If the pond depth were 5 feet, those values would be 330, 741, 408, and 930 acres, respectively.

The pond itself must be situated in an area which will not interfere with natural drainage, and must be lined to prevent leakage into or out of the pond. Finally, if the sludge is to be used for gypsum board, [9,p] then the sludge pond can be considerably smaller than the values listed above.

The magnesium oxide (MgO) process generates a magnesium sulfite/sulfate sludge, which is dried and sent to a regenerating plant (generally off-site), where sulfuric acid is produced and regenerated MgO is recycled to the scrubbing unit. The sludge pond is only a temporary holding pond and therefore will generally not exceed 30 acres in area.

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[o] Assuming 10,000 ton/day coal feed, .7% sulfur content, and based upon an extrapolation of values presented in reference 43.

[p] The Chemico sludge generated in a Japanese operation will be used as a raw material for gypsum board production, because natural gypsum is not abundant in Japan, while its abundance is greater in the U.S., and hence, its price is much lower.

The citrate process generates elemental sulfur as the solid end-product. The sulfur is stored for commercial sale upon demand. No permanent disposal land is required, only a temporary surface storage area of a few acres.

E. Mining and Transport

The quantity of land used at any given time during surface mining is not simply the land area being excavated. Additional lands are affected, including land where the spoils are stored, land used for haul roads, coal preparation, offices, loading facilities, and land in the midst of the reclamation phase. The total of these individual areas is referred to as total lands disturbed at any given time. The usual reference frame for computing disturbed lands is on an annual basis, but that generally only includes the new land mined and disturbed during the year and does not include the land under reclamation.

Since the length of time required for reclamation to be completed is an issue unto itself (to be discussed in Section II of this report), it is not easy to decide on an accounting procedure for disturbed lands. The reality is that the quantity of the disturned land will continue to increase annually until the first mined lands are reclaimed (by some operational definition). That means, for example, that if fixed disturbed land for buildings, rails, etc., is 10 acres, the amount of newly disturbed land is annually 200 acres, and reclamation of a piece of land requires 10 years; then the total disturbed lands after 5 years of mining would be 1010 acres; after 10 years, the quantity would be 2010 acres, where it would hold constant until mining ceased. Assuming that mining ceased after 20 years (and erosion was kept to a minimum during reclamation), the disturbed lands would decrease at the rate of 200 acres per year from the maximum point until 30 years after the original mining began, when the disturbed lands would have disappeared.

This is the method by which disturbed lands should actually be computed. However, this operational definition is dependent on the imprecise definition of reclamation time, as well as the hypothesis that secondary land disturbance through wind and water erosion and natural drainage disturbance does not affect the reclamation effort.

The number of acres newly disturbed each year (not total disturbed land) is dependent upon the quantity of coal mined and the tonnage of coal per acre (i.e., the thickness of the coal seam). The western seams apparently vary from between 20,000 to 100,000 tons of coal per acre. Mining 10 million tons per year requires about 500 acres in the first case and 100 acres in the second case. The general rule of thumb is that newly disturbed land is 2.5 times the actual land mined so that 1250 acres would be newly disturbed annually in the first case and 250 acres in the second case.

However, in some cases, particularly where coal seams are very thick and the overburden very shallow, the land may not be able to be regraded so as to ultimately offer a shallow enough grade for farming or wildlife grazing. In that case, plans may be made to create an artificial lake or pond.[q] However, such a procedure implies that there is no reclamation until after mining ceases, when reclamation would be deemed complete as soon as the pit was graded and filled with water. This means that a different disturbed lands' accounting procedure would be required than the one discussed above. Obviously, the use of the phrase "disturbed land" can be very misleading and all parameters must be spelled out before the numbers take on any meaning.

If a rail line is used for shipping coal, the amount of the land used for this purpose is the purchased right-of-way land. If the right-of-way were 50 feet wide, then the rail land use would be about 6 acres per mile of rail. The number of rail miles dedicated exclusively to coal transport (as in a unit train loop) multiplied by 6 acres would give the total impacted land directly from shipping. If the dedicated rail line in a given state were 200 miles long, then the land impacted would be 1200 acres. However, for the sake of completeness, a rail line causing a division of land may generate additional land impacts by creating a potential barrier to domestic grazing, farm equipment, or wildlife. Such an impact is impossible to assess in the general case, and must be considered on a case-by-case basis. A slurry pipeline would have similar impacts except that the right-of-way would be smaller (perhaps only 20-30 feet), thereby creating a smaller direct land impact. However, a surface pipeline will create a greater barrier to animals and farm equipment than a rail, thereby creating possibly greater secondary impacts than rail lines. If transmission lines are built for carrying electricity out of state, the right of way would be considerably larger than for either pipelines or rail lines. Barrier obstacles would probably not be created in prarie regions, but adverse effects could be created in wooded areas which would require significant clearing and habitat interruption. Furthermore, large transmission lines are aeathetically displeasing on the open prairie or in wooded areas.

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[q] Such is the plan for the Amax Bel-Ayr mine at Gillette, Wyoming.

F. Domestic

Each process will have a labor force in the construction and operational phases. This force will need to be housed. The land used for housing and auxiliary services should be included in land impact calculations. Chapter III has discussed process manpower needs, but the issue of how the labor force is domestically distributed on the land is beyond the scope of this report, and requires an additional analysis which may use Chapter III as a numerical starting base for the gross numbers of workers required for each phase of each process.

IX. PRESENT AMBIENT AIR STANDARDS

A. Sulfer Dioxide (SO_2)

The present primary ambient air standards[r] for SO_2 are 365 micrograms (ug)/cubic meter (m^3) average (mean) for a 24 hour period and 80 ug/m^3 annual average.[48]

SO_2 is an acidic gas which is quite soluble in water. This solubility leads to SO^2 being absorbed quite rapidly in the upper respiratory tract rather than passing deep down into the lungs. The acidity of the gas leads to irritation of the upper tract and the subsequent clinical symptoms. Clinical symptoms found to be associated with SO_2 exposure over a 24 hour period include increased respiratory illness requiring hospital care at 300-500 ug/m^3, and increased frequency and severity of respiratory disease associated with levels of 130 ug/m^3 over longer time periods.[49,50,51]

B. Particulate Matter

The present national primary standards for suspended particulate matter are 75 ug/m^3 annual geometric mean and 260 ug/m^3 maximum 24 hour concentration not to be exceeded more than once per year.[48]

The present standard does not differentiate between different chemical species of particulates, but considered them all as a total undifferentiated mass. Toxicological studies have indicated that inhaled particulates cause: (1) changes in pulmonary mechanics; (2) anatomic changes in animal tissue; and (3) changes in pulmonary clearance mechanisms (cilia action on foreign particles, bacterial clearance, etc.).

Early epidemological studies[s] showed that there was a prevalence of chronic bronchitis, emphysema, lower respiratory tract illness (pneumonia, chest colds, etc.) in populations exposed in average annual particulate concentrations of 125-175 ug/m^3 in conjunction with SO_2 concentrations of 90-120 ug/m^3.[52] The prevalent theory used to explain these lower respiratory effects was that the particulate absorbed the SO_2 and the particulate then carried the SO_2 to the lower tract, which the SO_2 alone could not have reached due to its upper tract solubility. The evidence for the short term (24 hour standard) is based on epidemiological studies showing increases in daily average mortality (death rate) associated with particulate levels of 150-200 ug/m^3 in conjunction with SO_2 levels of 265-530 ug/m^3 for 24-48 hours.[53]

The secondary standards for particulate matter are 60 ug/m^3 (annual average) and 150 ug/m^3 (maximum 24 hour average).

C. Hydrocarbons (HC)

The national primary standard for hydrocarbons is .24ppm (3 hour, 6-9 a.m. average). This standard is based entirely on the interactions of hydrocarbons, nitrogen oxides (NO_x), and sunlight inthe formation of photochemical oxidants (to be discussed subsequently).[54]. In the framework of these interactions, hydrocarbons are considered to be reactive or non-reactive, i.e., taking part in the photochemical reactions or not taking part in the reactions. All unsaturated hydrocarbons[t] are considered to be reactive, i.e., ethylene, propylene, butene, etc., as opposed to saturated hydrocarbons such as methane, ethane, butane, etc. Aromatic hydrocarbons[u] have reactivities intermediate between the olefins (unsaturated HCs) and the paraffins (saturated Hcs).

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[s] Statistical studies of disease entities in actual (non-laboratory) human populations.

[t] Hydrocarbons containing double or triple bonds between carbon atoms.

D. Carbon Monoxide (CO)

Carbon Monoxide is not associated with respiratory damage. Its toxicity rests on the fact that it combines with red blood cell (erythorocyte) hemoglobin to inhibit oxygen and carbon dioxide transport throughout the body. The CO hemoglobin complex is called carboxyhemoglobin. The national primary CO standards are related to carboxyhemoglobin levels attained in the blood. The standards are 10 milligrams (mg)/m^3 for 8 hours [48] (related to a resting blood carboxyhemoglobin level of 1.3% and a heavy work level of 1.4%) and 40 mg/m^3 for 1 hour (relating to a resting carboxyhemoglobin level of 1.3% and a heavy work level of 2.9%).

The health effects related to CO exposure include temporary central nervous system (CNS) damage creating time discrimination errors[55] (at 58 mg/m^3 for 90 minutes), and cardiovascular functional deficiencies (at 5% blood carboxyhemoglobin levels).[56]

E. Nitrogen Oxides (NO_x)

The common oxides of nitrogen which are toxic include nitrogen dioxide (NO_2) and nitric oxide (NO). The national primary standard covers only NO_2. The standard is presently 100 mg/m^3 (.05ppm) annual average.[48] However, the validity of that standard has recently been questioned (this will be discussed later).

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[u] Ring hydorcarbons with alternating double bonds between the carbon atoms.

NO_2 is a strong oxidizing agent, and as such has been shown to react with the double bonds of unsaturated lung connective tissues, such as elastin and collagen. This causes changes in lung tissue structure at levels of exposure of .5 ppm for 4 hours daily for a total of 6 days.[57] Laboratory experiments also have demonstrated that mice exposed to .4 ppm for 6 hours daily for a total of 3 months show a significantly increased susceptibility to respiratory infection.[58] Other studies have shown that various exposures at .5 ppm have caused emphysematic appearing lesions in mice.[59]

The Federal standard is based upon epidemiological studies performed on Chattanooga school children, which showed that long term exposure levels of NO_2 of between .06 and .11 ppm resulted in increased acute respiratory illness in families, decreased lung function in females, and increased bronchitis in school children exposed for two to three years.[60] However, as will be discussed later, that study used erroneous measurement methods and did not adequately account for the presence of suspended nitrates and sulfates.

F. Photochemical Oxidants

Photochemical oxidants include the entire range of peroxidized atmospheric hydrocarbons, as well as ozone (O_3) resulting from the interaction of NO_2, HC, sunlight, and molecular oxygen. Although the general chemistry of these interactions is understood, the specifics of the reaction dependencies on temperature, moisture, sunlight intensity, nature of HC, particulate concentration, and SO_2 concentration are as yet poorly understood. No frequently valid predictive models have yet been produced even for specific regions. However, research along these lines is continuing.

Ozone, like NO_2 is a very strong oxidizing agent. Furthermore, due to the decomposition of ozone . . . . $O_3 \longrightarrow O_2 + O$, atomic oxygen is formed. Atomic oxygen is a free radical species, and as such its reaction into vivo imitates the effects of ionizing radiation. Ozone is therefore referred to as a radiomimetic species (i.e., imitating radiation).

The adverse health effects of ozone are predominantly respiratory related. Toxicological results have demonstrated that mice show increased susceptibility to induced bacterial infection at exposure levels of .08 ppm for 3 hours.[61] In humans levels of .07 ppm for one hour caused impairment of function in student athletes.[62] Eye irritation is experienced at O_3 levels of .1 ppm.[63] The current national primary standard for O_2 is .08 ppm maximum for 1 hour.[48]

X. REEVALUATION OF THE AMBIENT AIR STANDARDS

Since the publication of the national ambient air standards in 1971, considerable research has been done to further investigate the effects of the regulated pollutants. Results of that research, along with possible new Federal actions, are now presented.

A. Carbon Monoxide

Recent research on CO health effects has been performed in the areas of aggravation of cardiovascular disease and psychological parameters. Horvath[64] has found diminution of visual acuity in subjects whose carboxyhemoglobin (COHb) levels reached 6%. Another study[65] has found that men with cardiovascular disease showed very significant electrocardiogram changes while driving for 90 minutes on a Los Angeles freeway during rush hours. Finally, recent EPA findings[66] demonstrate significantly lower exercise tolerance at carboxyhemoglobin levels of 3% as well as electrocardiogram changes during exercise at those COHb levels. These studies lead to the conclusion that the present ambient standards appear to be properly determined.

B. Hydrocarbon

The present HC standard is not based on health effects per se, but on reactivity in the oxidant formation cycle. That cycle is still incompletely understood, but the HC standard appears to be justified.

C. Photochemical Oxidants

Further health effects studies have been performed on the role of O_3 in disease aggravation and causation. Long term concentrations of O_3 at levels of .10 ppm for 6 hours per day have been shown to cause bronchitis and emphysema in experimental animals.

Furthermore, these animals also showed a decrease in the lipid fraction of the adrenal gland.[67] Another study, exposing hamsters to levels of .2 ppm O_3 for 5 hours, resulted in chromosomal breakages in the hamsters' white blood cells.[68] Given the evidence of respiratory disease and mutagenicity, the standard appears justified, but it seems to include only a very small margin of safety. Further research on synergistic relationships between oxidant and other pollutants is needed in order to conclude that the "at risk" population is sufficiently protected with adequate margins of safety.

D. SO_2, Total Suspended Particulates, Suspended Sulfates, and Sulfuric Acid Rain

1. Primary Standards

The standards which have been most severely criticized recently have been the ones for SO_2 and particulates. The criticism has come from energy industry proponents, on the one hand, who state that the scientific literature does not justify the stringent SO_2 standards. On the other side, environmental groups argue that the SO_2 standard is too weak in that it is covering up the true culprit, suspended sulfates.

The truth of the matter is that probably both sides are right. It now appears that the true culprit in the Donora, Pennsylvania inversion and the London episode in the 1950's was probably sulfate aerosols and suspended sulfate particulate, rather than some synergism between SO_2 and total suspended particulate matter.

In 1963, Mary Amdur's work on sulfate particulate and sulfate aerosol toxicity was published.[69] It indicated then that such chemical species as zinc ammonium sulfate, sulfuric acid, and other suspended sulfates had a far greater toxicity on experimental animals than did gaseous SO_2. The studies also indicated that sulfate particulate sizes in the range of .3 - 2.5 micron were the most potent. Although the mechanism of action is by no means certain, it appears that the health effects are most potent for the most acidic substances which can penetrate into the respiratory system most deeply. This would explain why zinc ammonium sulfate, although less acidic, than sulfuric acid, could be more toxic. This also explains why gaseous SO_2 (which upon reaction with water forms mild sulfurous acid) is less toxic than most of the sulfates, which are both more acidic, and, in the aerosol or particulate form, can penetrate the respiratory tract more deeply.

However, the laboratory findings languished until recently, when EPA's CHESS* program began identifying adverse health effects from suspended sulfates in actual community populations.[70] Effects studied included prevalence of chronic bronchitis in adults, increase in frequency or severity of acute respiratory illness in families; increases in acute lower respiratory tract infections in children; decreases in childhood ventilatory functions; aggravation of asthma attacks; and aggravation of cardio-respiratory symptoms in elderly patients with heart disease. All of the disease symptoms were associated with suspended sulfate levels of 3.0 ug/m^3 or less, going as low as $8ug/m^3$ while the SO_2 and particulate levels were present in five to 15 fold greater concentrations.

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*CHESS is EPA's Community Health Epidemiological Surveillance Studies program.

2. Secondary Standards

At the same time that the SO_2 primary standards were being questioned due to findings concerning sulfates, the SO_2 secondary standards were being questioned due to the phenomenon called "acid rain." This phenomenon is so called, because the sulfuric acid formed in the atmosphere will ultimately be washed out by rain. This rain has a low pH (high acid content), and may thus cause severe ecosystem and materials damages.

Studies performed by the Americans, Likens and Bormann, and the Swedes, Oden and Brosset,[71a&b] have demonstrated that rain water with a pH as low as 3.0 has been measured. (This value is about 1000 times as acidic as "normal" rain water. The predominant acidic chemical species found in the rain water was sulfuric acid. The effects of such acidic rain are as follows.

(a) Effects on Plants

A number of experiments have recently demonstrated the effects of acid rain on plants and trees. C.C. Gordon[72] has found that acidic rain causes stunting of immature pine needles. Sundstrum and Hallgren[73] found that lichens become much more susceptible to SO_2 damage after acidic treatment. Lichens plan a basic role in the conversion of bare rock to soil, and therefore they are the first group to establish themselves in plant and soil succession. Kratky,[74] et al. have found that acid rain fallout (originating from a volcano) has caused severe damage to tomato crops 40 miles from the origin of the SO_2 emission. Cowling and Schriner found that acid treatment (pH 3.5) caused damage to, and reduction in the dry weight yield of red kidney beans.

(b) Soil Leaching

A number of studies have shown that acid rain can leach calcium and other acid soluble nutrients such as iron, copper, manganese, zinc, and magnesium from the soil. This however, should present very little problem for the very basic soils found in the "Old West" Region.

(c) Aquatic Habitat Effects

A number of studies have recently shown that acid rain has seriously lowered the pH in small aquatic habitats (e.g., lakes and small rivers) with adverse ecological effects. However, most "Old West" Regional aquatic habitats should be sufficiently buffered by basic salts in the soil and water to avoid such acidity problems.

(d) Materials Damage

(1) Metals

Atmospheric sulfuric acid fallout has caused accelerated deterioration to take place in metallic structures. Metals which are most sensitive to such degradation include zinc or galvanized metals. The least sensitive metals are stainless steel and alluminun alloys. In all cases, the acid fallout increases the natural weathering rate of materials with these rates depending upon the metal sensitivity.

(2) Building Materials

Magnesium and calcium carbonates (sandstone, limestone, and dolomite rock) are very susceptible to acid corrosion. Damage occurs either through the solvation of a soluble sulfate salt, or through action of the physical properties of the newly formed sulfate whose properties are incompatible with the original materials, thus causing stresses and subsequent cracks in the material. Bricks and glazed materials degrade at a much slower rate than the stone substances discussed above.

(3) Synthetic Materials

Synthetic polymeric materials may be broken down into two major classes, i.e., free radical polymers (e.g., polyethylene and polystyrene) and condensation polymers (e.g., nylon, polyesters, acrylics). The former category is not very susceptible to acid damage. The latter group, however is rather susceptible to depolymerization via acid hydrolysis. Natural fibers, such as cotton and hemp are in the condensation polymer class and are therefore susceptible to acid hydrolysis.

Data is lacking on the effects of acid rain on surface coatings such as paints.

3. Formation and Control of Atmospheric Sulfates and Sulfuric Acid Mist and Rain

(a) General Discussion

Sulfuric acid (and subsequent sulfate) formation in the atmosphere has recently been extensively studied. It is clear that sulfuric acid production is proportional to SO_2 emission only in the long term. Ultimately more than 50% of the SO_2 emitted is oxidized to sulfuric acid. However, that may occur over a period of a week and after the SO_2 has travelled a considerable distance from its original point of emission. Swedish work[75] has traced acid rain fallout over 500 miles from the original point of SO_2 emission.

There are two problems then in attempting to control acid and sulfate formation. The first problem is associated with controlling the buildup of concentrations of sulfate, which could lead to the adverse health effects discussed earlier. This problem is confined to a region within approximately a 20-30 mile radius of the SO_2 point source. In this region SO_2 can build up and be oxidized to sulfate rapidly enough to prevent dispersion of the sulfate, and therefore pose a health problem. Therefore, this situation is characterized not so much by limiting SO_2 emission as by reducing the speed of atmospheric oxidation of SO_2.

The second problem is that of acid fallout (through rain) onto susceptible plants or materials (in the "Old West" Region soil leaching should present no serious problem as is found in the Northeastern U.S.). This problem is characterized not by concentrations, but solely by incessant fallout of acid which causes plant and materials damage. This latter problem is strictly emission related insofar as it is a function of total long term fallout.

The health damages from sulfates are concentration dependent. The control problem, which is posed in attempting to deal with SO_2 oxidation is then: what atmospheric or pollution parameters must be controlled along with SO_2 emission in order to insure a rate of

SO_2 oxidation, which will allow the sulfate product to be dispersed prior to the buildup of harmful concentrations of sulfate?

(b) SO_2 Oxidation Mechanisms

There are four primary chemical mechanisms which can account for sulfate formation. These are as follows:

1) Photooxidation in the presence of NO_2 and hydrocarbons (the same as in oxident formation)[76]

2) Oxidation in aqueous aerosol droplets, especially those containing ammonia[76]

3) Oxidation of solid particulates, especially iron oxide and alumina[76]

4) Oxidation on solid carbon particulate[77]

The relative importance of these mechanisms is not yet known with any certainty, but most investigators believe that the first two actually occur in the atmosphere. The third mechanism occurs, but due to the low concentration of particulates usually found in the air, its effectiveness is questionable. Mechanism four is newly propounded and based on very little laboratory and atmospheric surveillance work.

Coal burning power plants would affect sulfate formation through mechanisms 1, 3, and 4. Gasification and liquefaction plants, which would emit ammonia as well as NO_x, SO_2, and HC would affect sulfate formation primarily through mechanisms 1 and 2. Therefore, control of NO_x, HC, ammonia, and particulate emissions (and water droplets from wet cooling towers) might be as important for sulfate control as massive SO_2 control.

4. Standards for Sulfates and Acid Fallout

Presently the Federal government does not have an ambient standard for sulfates; nor do they have any policy as regards the region wide acid fallout problem. The Federal EPA is continuing its research into the health effects of sulfates, and a proposed standard might be expected within two years. The acid fallout problem is not a concentration dependent phenomenon. That is, the total acid deposited over some area during a given time is more important than any short term peak atmospheric concentration of acid or any short term deposit of acidity. The problem is also tricky because it covers a far greater geographical area around the original point source than is covered by any present day concentration dependent standard.

The State of North Dakota presently has an ambient sulfate standard of 4 ug/m^3, annual average, and 12 ug/m^3, 24 hour concentration not to be exceeded more than 1% of the time, as well as the same standards for sulfuric acid mist with an additional acid mist one hour standard of 30 ug/m^3 not to be exceeded more than 1% of the time.[78]

E. Nitrogen Oxides and Suspended Nitrates

The present Federal nitrogen dioxide ambient standard is .05 ppm annual average.[48] The standard was recently upheld by EPA, even as the Federal Reference Measurement (FRM) technique (Jacobs-Hosheiser) (used for measuring NO_2 in Chattanooga during the health study used to determine the standard) was being withdrawn by EPA due to its systematic deficiencies. Without getting too deeply into the technical problems encountered with the measurement technique, it may be briefly stated that EPA found it to be invalid in all air quality regions, except in Chattanooga. The measurements in Chattanooga have been upheld by a series of calculations attempting to correlate the now defunct FRM with other, supposedly more reliable, test methods.[79] To this date, the correlations have by no means been proven. This boils down to a situation whereby the FRM was found to be overestimating NO_2 levels everywhere (but Chattanooga) by a factor of two. Many air quality regions have been reclassified downward by EPA while the standard has remained constant. Recent epidemiological findings in Japan have associated NO_2 levels of .02 - .04 ppm, annual average, with increases in the prevalence of chronic bronchitis among non-smoking, non-occupationally exposed housewives.[80] These studies would be compatible with a tighter U.S. standard based upon the overestimate of NO_2 levels in the Chattanooga study. Other recent epidemiological studies have associated long term ambient levels of NO_2 of .03 ppm with increased mortality from hypertensive heart disease, nephritis (kidney disease), and lung cancer.[81]

There has also been recent research interest shown in the area of health effects associated with high short term peaks of NO_2. These studies have been laboratory in nature, i.e., exposing experimental animals to short term peaks of NO_2. Recent findings include the following.

Sherwin found increased protein levels in lung fluids of guinea pigs exposed to .4 ppm NO_2 for one week.[82] This could be as a result of an antibody response to NO_2 damaged tissue. Mueller, et al., have found changes in lung connective tissue of rabbits exposed to .25 ppm NO_2 levels for 4 hours per day for 6 days.[83] Sherwin has also found elevated uninary protein in animals exposed to .4 ppm NO_2 levels for 4 hours per day for one week.[84] This latter result may be supportive of the Sprey epidemiological finding concerning NO_2 effects on nephritis (i.e., kidney damage).[81]

Finally, very recent (unpublished) EPA Studies are finding adverse health effects associated with very low levels of suspended nitrates. The origin of these nitrate compounds is not well characterized as yet. However, it may be assumed that they result from secondary reactions of NO_2. The threshhold for damage levels found for nitrates appear to be in the range of 2 ug/m^3 - 8 ug/m^3.

Given the uncertainties in the measurement method for NO_x, the long term ambient standard, the short term effects, and nitrate damages, it is clear that some standards' changes (probably in the direction of tighter standards) can be expected within the next few years. This sould be of great importance with respect to the siting of potentially high NO_x emitting technologies, such as inadequately controlled MHD generators and advanced gas turbine generators.

XI. NON-CRITERIA AIR POLLUTANTS

A. Introduction

There are substances which are environmentally hazardous, but may be emitted to the atmosphere non-ubiquitously. These substances include trace metals such as mercury, beryllium, selenium, arsenic, and potentially carcinogenic polynuclear aromatic compounds (e.g. benzopyrene), toxic organics such as vinyl chloride, and other toxic substances such as hydrogen sulfide and hydrogen cyanide. These substances are not regulated by means of national ambient air standards, because of their relatively infrequent occurrence. The mechanism for Federal regulation is through the use of sections 111(d) and 112 of the Clean Air Act dealing with control of emissions of "non-criteria" or "hazardous" air pollutants. Presently, EPA has announced emission standards for mercury, beryllium, and asbestos. Although none of these standards affect any coal burning sources, there still remains considerable controversy over the problem of regulating mercury emissions from coal burning power plants. Other emissions from coal conversion operations not likely to be regulated on the Federal level in the near future include carbonyl sulfide, carbon disulfide, hydrogen sulfide, hydrogen cyanide, arsenic compounds, fluoride compounds, selenium, and polynuclear aromatic compounds. The former four substances are likely to be emitted from gasification and liquefaction plants: the latter four substances are likely to be emitted from coal burning power plants as discussed in Section I of this report. The following discussion centers on this distinction.

B. Power Plants

1. Mercury

Mercury emissions will be likely to occur from coal burning power plants. However, the EPA has determined that such plants could not, under any forseeable conditions, create an ambient situation which would allow mercury to exceed a 1.0 ug/m^3 concentration.[85] This is the ambient level which EPA believes to be protective of human health.

Airborn mercury is likely to be present as the elemental metal or as the oxide. The elemental form is rapidly converted to the Hg_2+2 (mercurous) or H_g+2 (mercuric form) after absorption from the lungs. It is these forms which are most biologically active. Mercury preferentially accumulates in certain tissues over time. The organs which appear most susceptible to mercury concentration are the kidney and brain, causing renal and brain damage to occur. No extensive epidemiological work has been performed on airborn mercury except for some occupational exposures. However, industrial data has shown that subclinical effects take place at exposures of 10-50 ug/m^3 of mercury.[86] These levels do not take into consideration the health status of the general population including young, old, infirm, and the pregnant.

EPA has concluded that mercury intake should be limited to less than 30 ug/m^3 of which 10 ug can be expected from ingestion, and thus 20 ug is the inhalation limit. Extrapolating backward leads to an acceptable ambient level of 1 ug/m^3 daily average.[85] This is a level not to be exceeded for elemental mercury. However, their analysis does not assure that the sensitive will be protected, nor does it assure that dietary intake will be limited to only 10 ug/day. This is especially important when one considers that although a coal burning source may not allow ambient concentrations above 1 ug/m^3 to be achieved, there will be fallout of the mercury from the atmosphere, possibly leading to increased water and dietary intake. The fate of atmospheric mercury fallout is not yet clear. Neither the transport distance nor the removal mechanisms are clearly understood (a situation that holds for other volatile trace metals as well). As an example of environmental buildup, a 1000 MW plant using .09 ppm mercury, 8000 BTU/lb. coal would emit 1.8 lbs. (817 million ug) per day, or 657 lbs. (298 billion mg) per year of mercury. This mercury could be deposited in water or soil, where it would concentrate over time.

Not only is concentration possible, but elemental mercury when added to soil may be oxidized to the mercuric ion, which ultimately may be converted by bacteria into the very toxic soluble methyl mercury or volatile dimethyl mercury. However, the latter reactions are pH dependent. The reaction rate is optimized at soil pH 4.5,[87] which is considerably more acid than most Western soils. However, between acid fertilized soils and acid rain fallout, some of the soils may be acid enough to facilitate such conversion, thereby allowing formation of methyl or dimethyl mercury. Even when the methylated species are not formed, the ionic mercury is capable of being picked up by plants or being leached into ground water supplies. The inorganic ionic forms, although not as toxic as the methylated forms, are still quite toxic to man. Although the EPA has not regulated mercury emissions form coal burning facilities, these emissions should be considered when assessing potential impacts of the siting of such facilities.

2. Arsenic

Upon heating arsenic compounds in the presence of oxygen at high temperatures, arsenous oxides are most probably formed. Under the conditions found in coal burning facilities these substances would vaporize and go up the stack. However, once cooled below about 400° F. they would coalesce to form the solid particle. It is not known how much arsenic is in the gas phase, or is emitted as a coalesced solid, or as a solid adsorbed on fly ash is emitted from coal burning facilities.

In any event, some of these mechanisms would act to bring arsenic into the atmosphere in an oxidized, and therefore not extremely toxic, state especially at the low concentrations to be expected. However, the arsenic compounds would fall out into the water and onto local soils. It is estimated that a 20 ppm arsenic containing coal, firing a 1000 MW power plant, would emit about 150,000 pounds of arsenic to the atmosphere annually. Although the fallout pattern of the arsenic is not known with certainty, it would not remain suspended for any great length of time, because after plume cooling, it would be in some particulate form. Because arsenic poisoning is cumulative, any increased environmental burden will ultimately increase human body burdens through diet and drinking water (the biological effects of arsenic will be discussed in more detail in the water pollution chapter.)

Finally, as with mercury, arsenic undergoes biochemical transformation in soil and water. Bacteria may reduce mildly toxic arsenates to highly toxic and volatile methyl arsines,[88] which may enter the atmosphere. Although the arsines are readily converted to a les toxic form in the atmosphere, a steady state arsine concentration may develop which could exert a toxic influence. Impact analyses of coal burning facilities should take into account arsenic emissions and subsequent ecological cycling as determined for the specific site in question.[89] As more research illuminates the ecological and public health consequences of arsenic emissions to the atmosphere such analyses will be easier to perform than at present.

3. Fluorides

Various fluorine containing compounds can be expected to volatilize during the combustion of coal and then to be emitted from the stack. It is assumed that about half the fluorine is volatilized as hydrogen fluoride and silicon tetrafluoride.[90] The environemental effects of fluorides are generally cumulative. However the mechanisms of action have been poorly characterized in plants, animals, and humans. The three most fluoride susceptible plant groups are gladiolus, sorghum, and conifers.[91] These groups experience adverse effects at levels of ambient air exposure of .5 mg/m^3 over long time periods. The adverse biological mechanism acting in flouride damage to animals in fluoride in combination with bone and tooth material causing weakening of those organ systems and resultant lameness and/or difficulty in feeding.

Studies have been carried out to determine the effects of fluoride contaminated hay or other cattle feed. One study demonstrated that hay contaminated by 40-60 ppm fluoride from aluminum smelter emissions was less harmful than sodium fluoride contaminated feed.[92] However, no such studies have been performed with respect to feeds contaminated with fluoride emissions from coal burning facilities. Therefore, it is not known whether these facilities' fluoride emissions are of a more or less toxic variety (considering equal concentrations) than those from aluminum smelters. Another study has been performed demonstrating that discernible dental mottling occurred in cattle eating feed contaminated by greater than 20 ppm fluoride.[93] However, lameness and reduced milk production did not occur in that study until the feed fluoride concentration had exceeded 50 ppm.

Unfortunately, there is no cut and dried method for evaluating the degree to which soil, water, and airborn fluoride contribute to fluoride accumulation in forageable plants. Furthermore, the uptake from each of those media is dependent on plant type, as well as soil and climatic conditions in a given area. This could possibly require a study of the background fluoride concentrations of forage material at a given impact site. This could be followed by experimental fumigations with coal derived fluoride emissions to assess the uptake of airborn (or air derived soil- and water-born) fluorides prior to determining the nature and extent of fluoride control required to protect the economic value of nearby foraging cattle.

It is presently believed that ambient air fluoride levels which are deemed protective of sensitive plant species, are similarily protective of adverse human health effects.

4. Selenium

Selenium is another volatile trace element found in coal. Its combustion products are not well characterized, but possibly include hydrogen selenide (H_2Se) and various selenates. As in the case of arsenic and mercury, the reduced form of selenium is its most toxic form. Selenium may enter the human body from the air via the lungs and the skin. Its fate in soil or plants after atmospheric fallout has not been well characterized. As in the case with many trace elements, long term, low level effects on humans have yet to be studied. The studies of selenium toxicity, which have been performed, have been generally with respect to the high levels (contrasted to the lower ambient environmental levels) related to occupational exposures.

Animal experiments have demonstrated that ingestion of selenium compounds causes the greatest accumulation to occur in the liver, kidney, and spleen.[94] Other studies have demonstrated that industrial selenosis (causing nausea, vomiting, and extreme fatigue) have occured in a number of cases when the measured H_2Se concentrations were less than .2 ppm.[95] Studies concerned with the effects of ambient, low level, long term exposures of selenium on human health and other environmental parameters are needed to determine the levels of selenium which are to be allowed to enter the ambient environment.

5. Polynuclear Aromatic Compounds

Polynuclear aromatic Hydrocarbons (PNAH) are fused rings of benzene rings. It has been found that many of these compounds are carcinogenic in laboratory experiments. One of the most potent carcinogens in this class if benzo-(a)-pyrene which is known to be present as a coal combustion product. However, the role of such compounds as airborn environmental carcinogens is just now being investigated.

The fate of such compounds in the environment is also poorly understood. The Federal EPA is now beginning an effort to investigate environmental pollution as it relates to carcinogensis.

C. Gasification and Liquefaction Plants

1. Hydrogen Sulfide (H_2S) and Carbon Disulfide (CS_2)

In Section I, it was assumed when computing emission factors for the various pollutants, that hydrogen sulfide, and carbon disulfide residuals would be incinerated to SO_2 and CO_2. However, some process designs may allow the emission of unconverted H_2S and CS_2 from the Claus or Holmes-Stretford plant directly into the atmosphere.

H_2S is readily absorbed through lung tissue and then enters the blood stream. At 15 ppm ambient concentration it causes eye irritation. Low levels of H_2S over long time periods may cause fatigue, headache, and insomnia. Long term exposures may have debilitating effects on central nervous system activities, but this area has not been extensively studied. The maximum permissible occupational exposure level allowed for H_2S is 20 ppm.[96] The state of North Dakota has set an ambient air standard for H_2S which is the following:[31] .032 ppm maximum 1/2 hour concentration not to be exceeded more than twice in any 5 consecutive day period: and .054 ppm maximum 1/2 hour concentration not to be exceeded more than twice a year.

Human carbon disulfide toxicity has been studied primarily in occupational environments because of its widespread use in the production of synthetic rayon in the 1950's. The toxicological mechanism is believed to be the removal of trace copper ions by chelation. One study performed with rayon workers in Japan[97] noted that when occupational exposures were between 40-50 ppm in the air, significant numbers of workers developed mental disorders, fatigue, and gastritis. These workers were also found to be deficient in trace copper and zinc. In later years, after the allowable concentrations in the occupational environment were reduced to between 5-15 ppm, significant numbers of workers were diagnosed as having chronic clinical renal (kidney) dysfunction. Autopsies on some of the workers found significant kidney tissue changes similar to those in cases of diabetes mellitus. No long term, low exposure level ambient air studies have been performed to evaluate the effect of CS_2 on various susceptible segments of human populations.

H_2S is produced naturally and it is presumed that its ultimate face is to be oxidized atmospherically to water and SO_2. It is also presumed the CS_2 would ultimately be oxidized to CO_2 and SO_2. Therefore, fallout and biological concentration of these substances should be of little concern; rather only the maximum concentrations that may be generated due to their process related emission.

2. Other Unregulated Emissions

Gasification and liquefaction processes will produce quantities of hydrogen cyanide. However, it is expected that most of this gas will be dissolved in the waste water stream for ultimate disposal in the waste water. However, some of the gas may be emitted with residual H_2S after the sulfur removal operation. The health effects associated with cyanides are discussed in some detail in the next chapter on water pollution.

It is expected that the tar fraction of gasification and liquefaction processes will contain polynuclear aromatic (PNA) compounds. In these processes, most of the tars are kept within the plant, as they are economically valuable as retained products. However, in both processes, the waste water may contain some of the compounds and it is quite probable that some PNA evaporation from the waste pond is to be expected. A recent study of death rates from cancer around Providence, Maryland[98] has associated the cancers with carcinogens evaporated from a chemical reprocessing plant's evaporation pond. The PNA's generated in these processes should be qualitatively similar to those generated during the combustion process discussed in the preceeding section. As was emphasized in Section I, evaporation rates for these compounds will be very dependent on pond dimensions, ambient temperatures, the chemical nature of the pond water, the rate of natural oxidation of the PNA in the pond itself, as well as the actual amount of PNA emitted to the pond over time. The latter value will be a function of the actual separator removal efficiency specifically applicable to the PNA tar fraction.

XII. WATER POLLUTION

A. Introduction

As was stated previously in Section I, it has been assumed that most of the gasification, liquefaction and electric power plant waste water will be sent to evaporation ponds from which water will continually evapoate, some organic substances will be degraded and salts of both a toxic and non-toxic nature will accumulate. Any analysis of runoff or ground water intrusion from these ponds must be performed on a site by site basis. However, this section will discuss the environmental aspects of the more important pollutants found in these waste waters. It is emphasized that the concentrations which cause noticeable environmental damage are not necessarily those which will ever be in existence in actual ambient ground or surface waters. However, the avoidance of such concentrations will help to dictate the degree of pond integrity required at the industrial site. Insofar as domestic sewage is concerned, there may be municipal discharges directly into surface waters, which will have the effect of reducing water quality in those bodies of water. The resultant water quality degradation will depend on many variables, and is therefore not easily predictable without a complete impact study of the actually affected waters. In addition to the problems with toxic effluents and domestic sewage, all coal conversion processes will generate large quantities of ash for disposal. The disposal will more than likely take place in a pit and toxic elements may be subject to leaching into the ground water. Finally, mining activities allow soil erosion to take place thus creating a possible sediment water pollution problem.

B. Pollutant Effects

The pollutants which are likely to be present in gasification and liquefaction wastewater include compounds of arsenic, mercury, ammonia, cyanide, and phenols. The major water pollutant associated with electric power generation is chlorine from cooling tower blowdown. Chemical pollutants may find their way into ground water from leaching of buried conversion process ash fractions. In particular, cadmium presents a problem in buried ash. Domestic sewage will generate a chlorine problem along with a problem of organic oxygen demanding material. Finally, mining activities, allowing soil erosion may create turbidity and a suspended solids problem.

1. Arsenic (As)

Arsenic occurs primarily in two chemical forms, trivalent and pentavalent. The trivalent form is the more toxic of the two. Ambient arsenic concentrations in most U.S. drinking waters range from a trace to .1 mg/liter.[99] Inorganic As is readily absorbed from the gastro-intestinal (GI) tract, the lungs, and even slightly through the skin.[100] During chronic exposure situations As is found to accumulate in bone, muscle, and skin. For the past 150 years As has been suspected of playing a role in carcinogenesis, but it has never been pinpointed as a carcinogen.[101]

Symptoms of mild chronic poisoning include GI catarrh, kidney degeneration, tendency to edema, polyneuritis, bone marrow injury, and dermatitis. Manifestations of arsenic poisoning have been noted in Chilean children using a water supply containing .8mg/ liter As. Because As does not accumulate along the food chain like mercury, its main toxic effect is from drinking water. One occurance of acute As poisoning in America happened in 1930. A group of children in Minnesota were found to have acute As poisoning symptoms after drinking water from wells containing between 11.8 and 21 ppm As.[102] It appears that an arsenic containing pesticide had been used against grasshoppers, and that the As had permeated to the ground water contaminating the well.

Concerning arsenic toxicity to aquatic life, one study reports that 1.1 - 2.2 mg/liter As is fatal to perch in 2 days.[103] However, the pentavalent form is much less toxic than the trivalent form. The former is barely affecting Daphnia in Lake Erie at levels of 18-31 mg/liter of sodium arsenate.[104] Effluents of arsenic from gasification and liquefaction processes would probably be in the trivalent form. The time required for oxidation of the trivalent to the pentavalent in the environment of the waste pond is not known.

2. Ammonia (NH_3)

Ammonia (NH_3) is a pungent, colorless, gaseous alkaline compound that is highly water-soluble. Although normally present in most waters as a degradation product of nitrogenous organic matter, NH_3 may also reach ground and surface waters through effluents from gasification and liquefaction processes and through sewage and sewage effluents.

Ammonium hydroxide, the result of ammonia's reaction with water, easily dissociates into ionized ammonium and hydroxyl ions (NH_4+ and OH-) in most natural waters - ammonia in its ionized form is usually nontoxic to aquatic life. However, with increased water alkalinity (high pH) (the case with gasification and liquefaction effluents) and temperature, the amount of un-ionized ammonia increases proportionally. Ammonia's toxicity is directly related to the concentration of its un-ionized form in water.[105] NH_3 may also react with chlorine from sewage disinfectants and cooling tower blowdown water to form chloramines which are potentially toxic to fish.

A generally accepted range of lethal concentrations of NH_3 in water is 0.2 mg/liter, with trout the most sensitive fish tested and carp the most resistant. Concentrations below 0.2 mg/liter may not kill significant numbers of fish, but may exert adverse effects. Investigations of ammonia toxicity include: (i) Using about 1 mg/liter NH_3, Fromm found that 50% of the rainbow trout tested died within 24 hours;[106] (ii) Gill hyperplasia (abnormal proliferation of cells) was noted in salmon with concentrations ranging from 0.006 to 0.27 mg/liter NH_3.[107]

3. Cyanide (CN)

In the reducing environment of gasification and liquefaction plants, cyanides will be readily formed at moderate temperatures. Two forms of cyanide, hydrocyanic acid and cyanogen chloride, were used as chemical warfare agents in World War I. Natural biological processes may also produce organic compounds containing cyanide; it is found in seeds of plants belonging to the rose family and at times in plum and peach pits, as well as laurel leaves and certain grasses.

Potassium cyanide (KCN) and sodium cyanide (NaCN), commonly occuring sources of cyanide, are readily soluble in water. Dissociation of these metals in water begins at pH values of 8.0, and increases with decreasing pH, freeing the cyanide radical to combine with the hydrogen ion, thereby producing hydrocyanic acid, which is toxic to aquatic life. Wastewater discharges from gasification and liquefaction processes may cause pH fluctuations in the receiving water (probably evaporation ponds), which could affect HCN production, and therefore the toxicity of the cyanide present.

The cyanide radical combines with many heavy metal ions to form complex metallocyanide anions, whose stability is highly variable. For example, when cyanide combines with silver or copper, the anion is highly unstable, allowing dissociation to occur with subsequent production occuring rapidly in near-neutral and acidic environments. At the other extreme is cobaltoyanide, which cannot be destroyed by acid distillation. Although the iron cyanides are very stable, the material dissociates in the presence of sunlight to release the cyanide ion, a process called photodecomposition.

The physiological mechanisms for cyanide toxicity have not been clearly elucidated. Cyanide reacts with hemoglobin and methemoglobin in the blood stream, interfering with oxygen transport and decomposing waste metabolites, all of which results in anoxia, characterized by cyanosis, a bluish coloring of the extremities.

The persistence of CN in water is highly variable, depending on its chemical form, concentration, and toxicity, and the nature of other components in the water. Permanganates and chlorine, both strong oxidizing agents, may destroy cyanide. Cyanogen chloride (CNCl) may result, however, when chlorine is used to oxidize strong cyanide solutions and the reaction is not carried through to completion. This latter situation may be very possible if cooling water blowdown (containing dissolved chlorine is added to evaporation ponds). However, due to its slightly soluble nature (compared to the very soluble HCN), and its (Cyanogen/chloride) very low boiling point (about 60° F.), it would most likely be emitted to the atmosphere. Hydrogen cyanide is the species which will probably be produced in the coal conversion processes, but the HCN may be neutralized in the probably alkaline medium of the evaporation pond. This will leave the cyanide in a less toxic state than the one in which it was produced with the exception of the possible CNCl reaction cited above.

HCN is probably the most toxic form of CN in water. However, because of CN's variability in water, cyanide safety criteria must be based on the concentration of total cyanide ion present in the water, as this is the potential toxicity regardless of chemical and physical fluctuations. Cyanide ingested by humans at 10 mg or less per day is not toxic,[108] so concentrations of cyanide in water must be very high to result in lethal toxic effects. A maximum concentration of 200 ug/liter for domestic water supplies provides a reasonable margin of safety. The toxicity of cyanide to freshwater fishes has been shown to be variable, due to the differing forms of CN, pH values of the solutions tested, and the decomposition of CN during test exposure.

4. Mercury (H_g)

Mercury, a silver-white mobile liquid metal at normal temperatures, is a nonessential, nonbeneficial element biologically, with a high toxic potential. Its use is widespread for medical and agricultural purposes because of its toxicity. Its physical and chemical properties make it useful to industry as a liquid metal and catalyst. It is distributed throughout the environment.

The toxic effects of mercury vary with its form and environmental mode of entry. They may be acute or chronic. The fatal oral dose of mercuric salts, which are more toxic than the mercurous salts, ranges from 20 mg to 3.0 g.[109] Chronic mercury poisoning results from exposure to small amounts over extended time periods. Inorganic mercury poisoning (chronic) has usually resulted from industrial exposure, whereas organic mercury poisoning has been associated with accidents or environmental contamination. Alkyl compounds of mercury, the most toxic to man, can produce death by ingestion of only a few milligrams.[110]

The natural mercury content of unpolluted U.S. rivers from 31 states where naturally-occuring deposits of mercury are unknown is less than 0.1 ug/liter.[111]

The recent discovery that microorganisms can convert any form of mercury into its toxic methyl and dimethyl forms makes any form potentially hazardous. Since mercury in water can be changed biochemically, the total mercury level should be the basis for any protective mercury standard. Whenever a toxic substance such as mercury or one of its compounds is added to the aquatic environment, a shift in the biological process towards synthesis, not degradation, results. In other words, toxic methyl mercury may result from a natural biological conversion, and thereby become available to aquatic life.[89] Fish, which take up mercury directly from the water and food, accumulate the substance quickly, but eliminate it slowly, resulting in mercury concentrations in the fish, sometimes 3,000 fold higher than in the water.[112]

A whole blood concentration of 0.2 ug/g of methyl mercury in man is the lowest associated with toxic symptoms. This state arises from prolonged, continuous exposure of approximately 0.3 mg Hg/70 kg body weight/day. With a safety factor of 10, a total of 0.03 mg Hg/person/day should be considered as a possible maximum dietary intake.[85] Levels of 0.1 mg/liter Hg and 0.5 mg/kg body weight should not be exceeded in blood and tissues of livestock, respectively. An acceptable level in their drinking water at 0.05 ug/liter Hg.

Fish have been tested for effects from chronic exposure to organomercurials with respects to survival, growth, and reproduction. In a study by McKim and Olson,[113] where 3 generations of brook trout were exposed to methyl mercuric chloride, several results were recorded: the offspring of fish exposed to 0.93 ug/liter showed reduction in growth 90 days after hatching; second generation fish exposed to the same concentration for 24 months showed no spawning and had a mortality of 94%.

Significant reproductive impairment was noted in all invertebrate (Daphnia magna) at concentrations of 2.7 ug/liter and 0.04 ug/liter for mercuric chloride and methylmercuric chloride, respectively.[114]

Because of methylation and bioconcentration of methylmercury, mercury criteria must accommodate the food chain transport path from aquatic organisms to man. Methylation, althouth its rate is highly dependent on water quality conditions, can occur between pH values of 5 and 9 under aerobic or anaerobic conditions, i.e., it can and will occur in most natural waters. Methylation of mercury apparently takes place in the water-sediment interface where benthic organisms are most active; these organisms absorb mercury which is transported to fish, if eaten.

It is not known what the chemical form of the mercury leaving gasification and liquefaction plants will be. Under the reducing conditions present, the mercurous inorganic form may exist, which may subsequently be oxidized to the mercuric form in the pond. However, due to the relatively high pH in the pond, conversion of the mercuric form to methylmercury in the pond would be very slow. Furthermore, if the pond were lined, there would be no bottom sediment as a habitat for methylating bacteria, which would also reduce the possibility of methyl mercury formation in the pond itself. However, there is a possibility that methyl mercury may be formed directly in the reducing methane atmosphere of the process reaction vessel. Regardless of the actual form of the mercury effluent, seepage into ground or surface waters could allow any mercury to be methylated to the most toxic methyl mercuric form.

5. Phenol

Phenolic compounds consist of a variety of aromatic organic chemicals with phenol (C_6H_5OH) as the parent compound. Included are mono-di and poly-hydric (referring to the number of -OH groups with a replaceable hydrogen atom) phenols. Phenols arise from any coal distillation process, as discussed previously in Section I, and thus will be generated in all liquefaction and some gasification processes.

Adverse ecological effects from phenols may occur in the following ways; direct toxicity to fish, reducing available dissolved oxygen in the water due to its high oxygen demand, and by the tainting of fish flesh.

The toxicity of phenol to various fishes is dependent upon the nature of the physical chemical variables present in the water.[115] Enhancement of toxic effects arises from increased salinity, decreased temperature and reduced dissolved oxygen concentrations. The former two variables are both present to some degree in many of the surface waters in the Old West Region. Concentrations which were lethal to 50% of the trout embryos tested during a 24 hour period (24 hour LC50) were 5 and 3 mg/l respectively for phenol and O-cresol.[116] Rainbow trout were killed in 7.3 mg/l phenol in 2 hours and in 6.5 mg/l phenol in 12 hours.[117] In these cases severe pathological changes in gill tissue were noted.

Another major problem associated with phenols is the odor problem, which is generated both in water and in reaction with fish flesh (tainting). In this respect, chlorinated phenols create a more noxious problem than unsubstituted phenols. Phenols can easily become phlorinated in an evapoative pond by reaction with chlorine from cooling tower blowdown. Odor thresholds in water have been found to range from 55 mg/l from p-cresol[118] 2 mg/l for 2- chloro-phenol.[119] Odor and taste thresholds for fish flesh tainted with phenol compounds range from .lmg/l to 15 mg/l for various mono- and di-chloro phenols 120,121 with o-chloro phenol being the most effective in causing the tainting.

The nature of the chemical reactions which phenols might undergo in an evapoation pond, is not known. The lifetime of the phenols in such a pond is also not presently known.

6. Chlorine

Molecular Chlorine, Cl_2, is really soluble in water, wherein it reacts by the following reaction: $Cl_2+H_20 \rightarrow HOCl+H^++Cl^-$. HOCl is hypochlorous acid, which may dissociate to form H^+ ions and hydrochlorite (OCl-) ions. The latter is the active oxidizing agent in bleach. As mentioned previously chlorine effluents are associated with cooling tower blowdown from gasification and liquefaction, and especially from large wet cooled steam electric generating plants.

Chlorine can also be expected to be used in sewage treatment plants in the final disinfectant stage.

Blowdown waters from gasification and liquefaction plants can be expected to go with other waste waters, probably into evaporation ponds. Once these hypochlorite ions (rather than undissociated hypochlorous acid due to the alkaline pH) can be expected either to build up, react with cyanides to form cyanogen chloride (discussed previously), react with phenols to form chloro-phenols, or react with nitrogenous materials to form chloramines. It is not known how blowdown waters from electric power plants are to be treated; if ponded however, there should be hypochlorite build-up without any side reaction, because of the absence of phenols, nitrogenous organics, and cyanides in power plant waste water. Chlorine will also be discharged from domestic sewage waste waters. In this case chloramine formation should occur to a large degree.

Chlorine toxicity is somewhat pH dependent as the most toxic form of the substance in water is the undissociated HOCl. Chloramine toxicity to fish is about the same as free chlorine.[122]

In field studies performed on chlorinated sewage discharges,[123] no fish were found in water with a chlorine concentration above .37 mg/l. Of the 45 species observed in the study, the brook and brown trout were the most sensitive, not being found to remain in water whose chlorine concentration exceeded .02 mg/l. Another study in Michigan found that 50% of a rainbow trout sample died within 96 hours in water containing .014 - .029 mg/l chlorine.[124]

Other studies have indicated even lower long term thresholds of chlorine with respect to rainbow trout toxicity. One study indicated that rainbow trout avoided water whose chlorine concentrations were above .001 mg/l.[125] Another study demonstrated that trout fry died within two days in water containing chlorine at a .006 mg/l level.[126]

7. Cadmium (Cd)

Cadmium is a soft, white easily fusable metal related to zinc and lead in many properties. It is readily soluble in mineral acids. Biologically, it is nonessential and non beneficial, and has a high toxic potential. It is virtually ubiquitous in the environment. Concomitant with increased industrial production and use, there have recently been a number of acute cases of cadmiosis. Cd may be partially responsible for such pathological processes as testicular tumors, renal dysfunction, hypertension, arteriosclerosis, growth inhibition, chronic disease of old age, and cancer.

Cadmium is found in coal and is not very volatile either at gasification or liquefaction process temperatures, or at coal combustion temperatures found in steam electric generators. Therefore, it will be found in the ash of the processes. It will probably be found in the oxide form in combustion ash and in the metallic, or in the simple salt form in gasification and liquefaction ashes. The problem of leaching into ground water is most serious for cadmium, because mercury, arsenic, and selenium will have volatilized, and therefore will no longer be present in the ash when disposed. The chloride and sulfate salts of cadmium are quite soluble in water and would be easily leached over time. The oxide is very slightly soluble in water, as is the sulfide and the metal. The latter are even less soluble in alkaline solution, which is what most of the deeply percolated Western ground water will be. However, if rainwater is strongly acid from sulfuric acid fallout around the ash disposal site (discussed in Chapter IV), and if the ash is buried in a shallow pit, then considerable leaching may occur under those acid conditions.

Cd is toxic to man when ingested or inhaled at certain concentrations (concentration, not absolute amount, determines Cd toxicity). 13 to 15 mg/liter Cd is considered to be the emetic threshold concentration for man (equivalent to 1.3 to 3.0 mg of Cd ingested).[127] An example of acute Cd poisoning is the case of the many Japanese suffering from itai-itai disease from drinking water containing excessive Cd[128] -- about 50% of the 200 who suffered from this disease have died. The disease produces loss of bone minerals. Yamagata and Shigematsu[129] estimated the "no-effect" daily intake level of Cd in an endemic itai-itai area at 600 ug.

Three consecutive generations of brook trout were exposed to Cd concentrations ranging from 0.5-6.4 ug/liter in water with the following approximate characteristics: 41-45 mg/liter as $CaCO_3$, alkalinity of 38-43 mg/liter, pH 7.4. Second generation fish exposed to 6.4 and 3.4 ug/liter Cd were smaller at 3 months when compared to fish exposed to lower concentrations. Extensive mortalities were suffered by first and second generation fish during spawning in 3.4 ug/liter Cd. In soft water, the lowest Cd concentration not causing growth reduction among 4 species after 60-120 days of exposure was 1.2 ug/liter.

Yamagata and Shigematsu[129] demonstrated that food cultured on Cd-polluted soils, irrigated with Cd-polluted water, can accumulate enough Cd to be hazardous to humans who consume these foods.

Salmonids and cladocerans appear to be the most sensitive among the organisms tested. Increases in hardness and/or alkalinity have been demonstrated to decrease the toxicity of Cd in acute freshwater mortality tests. Criteria necessary to protect fish and other aquatic life are more stringent than those necessary to protect public water supply or other uses.

8. Suspended Solids and Turbidity

In general, suspended solids consist of two main classes: inorganic (non-volatile) and organic (volatile). The former class would arise from high clay content solid erosion with subsequent run-off into surface waters, where the small clay particles would remain suspended giving rise to a cloudy or turbid water condition. Organic suspended particles are important because, although they are degradable over time, they may harbor potentially hazardous microorganisms which did not contact a disinfect (e.g., chlorine) during final waste water treatment.

Due to the likelihood of wind and water erosion around mining pits, in the process of being reclaimed, large quantities of clay silt may reach man-made recreational lakes and other surface bodies of water. Another potential source of suspended solids is from coal pile runoff around a conversion plant. One of the major problems arising from the turbidity is decreased visibility beneath the water surface. Such visibility impairment creates safety problems for swimmers who cannot see submerged hazards, as well as for lifeguards attempting to find drowning swimmers.[130] Turbidity also affects the esthetic quality of the water course which experiences the problem.

Effects of suspended solids on fish and freshwater ecology may be broken down into the following areas:[131]

(i) direct action on fish swimming in water in which solids are suspended, resulting either in killing them, reducing their growth rate or their resistance to disease, etc.

(ii) prevention of successful egg and larval development.

(iii) modification of natural fish movement and migration.

(iiii) reduction of available food to the fish.

The same study[131] also concluded that suspended solids levels below 25 ppm generally had effect on fresh water fisheries; however, levels of 25-80 ppm would begin to show slightly decreased fish yields. Levels of 80-400 ppm would support only marginal fisheries, and virtually no fisheries would exist about levels of 400 ppm. Concerning short term high levels of suspended solids, the study indicated that levels of a few thousand ppm for a few days could have harmful effects on the fish population. Such effects could arise from severe erosion during infrequent but very heavy rainstorms in the region. The EIFAC study also demonstrated that, where settleable solids blocked gravel spawning beds, high hatching mortalities occured. The latter effect appears to be related to blocked oxygen and carbon dioxide diffusion capability arising from silt attachment to the eggs.

Another problem arising from suspended particles is that associated with the light scattering properties of the particles. This results in a reduction of light penetration, thus reducing the depth at which plants may grow, creating a reduced food production problem for the fish. Additionally, the upper surface waters become preferentially heated, thus decreasing mixing with waters from lower depths and causing nutrient and oxygen deficiencies in the lower waters.

A further problem arises if such turbid water is used for irrigation purposes. Use of such water leaves a clay crust, on topsoil, which will impede water flow and may also leave a film on crop (or forage) leaves reducing sunlight penetration and ultimately the growth of the plant. Finally, water delivery systems may be clogged up. The damage potential is not only concentration dependent, but also total sediment deposited dependent as is easily seen by referring to the last few effects noted above. It will therefore require close monitoring of actual streams and lakes in order to determine whether sedimentation and high suspended solids concentrations are causing problems such as discussed above.

9. Biological Oxygen Demand (BOD) and Dissolved Oxygen (DO)

Most organic materials when placed in water will be oxidized by oxygen dissolved in the water either with or without the aid of aerobic bacteria. Such use of oxygen reduces the dissolved oxygen available to fish and hatching fish eggs, thereby decreasing their viability. In addition, organic material especially from sewage treatment plants may act as nutrient material for algal growth, which will use oxygen for its respiratory functions. Domestic sewage will increase in the regions where coal is developed due to labor force immigration. Such sewage, even with 85% BOD removal (secondary treatment), will still create a DO reduction in presently high DO streams and rivers. The DO reduction is most acute in summer months due to the increased rate of oxidation from the higher water temperatures. Spawning trout require DO levels of at least 7-8 ppm. Other fishes require DO levels of about 6 ppm. As the levels are reduced even further, anaerobic, septic conditions may arise creating potential disease hazards and noxious sulfide odors.

XIII. EFFECTS OF STRIP MINING

A. Introduction

Strip mining in the West is associated with three major environmental problems. First of all, reclamation is difficult because of the semi-arid climate in the region (annual rainfall varies from between 9 inches in parts of Wyoming, to 15 inches in mining areas of Montana, to greater than 16 inches in parts of North Dakota). Secondly, many strippable areas, especially in Northeastern Wyoming have very shallow overburden layers as compared to the thickness of the coal seam. This situation creates a pit, which is almost impossible to regrade to the original (or closely related) contour. Finally, there are potentially serious problems associated with acquifer disturbance due to mining and blasting.

B. Reclamation Potential and Regraded Spoils

1. General Discussion

Recently considered Federal legislation would have established minimum reclamation standards for strip mined Western lands. However, such operating standards cannot assure that natural, climax grassland communities can be quickly re-established after being seriously altered by strip mining activity. In situations where sufficient overburden exists to fill up mine pits, the disturbed area can be regraded, seeded, and fertilized. However, the growth potential of grasses and shrubs is severely limited due to the natural conditions in the area. There are no general rules of thumb concerning which grassland species are most adaptable to raw mine spoils or modified mine spoils. Furthermore, there have been no assurances that, once a plant cover is established, it can be maintained especially in the presence of environmental stresses such as grazing or periodic periods of drought or severe frost during the growing period. On the other hand, where insufficient overburden exists to allow regrading of the affected area, pits will remain. The wall may be graded and the pit may be filled with water to create an artificial lake. However, the lake may create an undesirable water pollution problem, or may not sufficiently hold water, thereby leaving a dry pit in the ground.

Little attention has been paid to Western strip mine reclamation until very recently. Research aimed at uncovering the basic facts concerning the applicability of certain reclamation procedures to Western coals is still in its early stages. In order to increase the reclamation potential of any strip mined site, a high level of research, and careful adherence to best reclamation practices, must be maintained. What follows is a summary of recent field studies concerning reclamation practices and plant response on actual mine spoil materials.

There have been two major efforts devoted to Northern Great Plains strip mine reclamation research. One study focused on North Dakota lignite mines[132] and the other on Montana mines.[133] The effort in Montana investigated reclamation procedures from contouring and compacting through seeding, fertilizing, and plant species succession. The North Dakota effort has primarily focused on modification of the physical and chemical properties of the spoil material in order to make it more compatible with plant growth and maintenance. Both studies indicate that the major limiting factors appear to be water permeability, salinity, and physical stability of the soils.

The Montana study[133] has investigated various physical configurations for spoil material, including ridging (dozing), gouging, and chiseling. These manipulations were investigated with respect to the soil's ability to hold moisture and initiate plant growth. In all cases soils shaped and gouged, or dozed, were more successful in trapping moisture and allowing initial plant stabilization, than were smooth or chiseled soils.

The North Dakota study[132] indicated that the spoils are not sufficiently saline or alkaline to cause direct saline or alkaline toxicity. However, the spoils were found to be high in sodium relative to calcium and magnesium. The spoils were also found to have high percentages of clay (greater than 40%) and high sodium adsorption ratios (SAR). The topsoils of that region generally were loams and loam-clay mixtures with SARs considerably lower than the spoil material . High clay and exhangeable sodium content generally causes a reduction in the permeability of water through the soil. This is so because the small clay particles mechanically fit close together (compared to large sand particles), thereby blocking percolation. Furthermore, the high sodium levels create regions where the sodium ions "hold" the water molecules in a complex not allowing them free passage to percolate into the soils. Therefore, the North Dakota results indicate that the spoil materials require treatment to increase the percolation capability in order to allow water to reach the deep roots of mature plants, and to prevent soil erosion and the ultimate erosion of seeds and plants themselves.

2. Non-Nutrient Soil Improvement

Both the Montana and North Dakota studies investigated methods of improving the rate of acceptable soil development. The North Dakota study aimed at reducing sodium content of the soil through exchanges with other cations, such as calcium and magnesium. This exchange would substitute necessary plant nutrient cations for sodium, as well as allowing for increased water permeability. The other soil improvement technique attempted was mulching. Mulching can create mechanical rivulets into the soil as well as keeping soil moisture from rapid evaporation by acting as an insulating body between the soil and ambient atmosphere. In the Montana study, soil development was studied with respect to increasing organic material in the soil in the Colstrip area, and by creating buffer areas between saline spoils and topsoil in the very dry, saline Decker region. The results of these soil development studies are as follows.

The North Dakota study investigated plant yields with punched straw mulch and gypsum as amendments to spoils. In general, although gypsum (calcium sulfate) aided slightly in reducing the SAR of the soil, plant growth studies showed little difference between raw spoil, and gypsum amended growth. However, over long time periods, addition of large amounts of gypsum may aid in building a less sodic soil. Gypsum may be easily obtained as a waste product of lime/limestone scrubber operations as discussed in Phase I. Another soil improvement operation attempted was that of punching straw mulch into the soil. Results showed temporarily increased plant growth relative to raw spoils, but the growth was not sustained over any great time period.

The Montana study investigated a biological technique for increasing the organic fraction in the shaped spoil. Decaying roots add organic material to the soil. Therefore plants which produce greatest root growth should be desirable from the point of view of organic material production. The best root producers were a range pasture mixture and an annual perennial mixture. Of the annuals, sorghum and rye were the best producers relative to millet, sudan, and rape. This technique was investigated in the Colstrip area. In the highly saline Decker area, a buffer technique was attempted. The concept involved was that a buffer between topsoil and very saline subsoil could prevent upward saline water capillary flow caused by the high evaporation rates at the soil surface. The buffers evaluated were low salinity spoils, and scoria, a water impervious clay material. These evaluations have not yet been completed.

3. Topsoiling

Topsoil is seen as an important addition to spoil materials for the following reasons. It holds and conducts water quite well; it contains organic nutrients material needed for plant growth; it contains microflora necessary for converting organic nutrients into usable inorganics. Furthermore it is generally much lower in sodium and other salts than the subsoils and therefore creates no undesirable saline toxicity problems. Studies on North Dakota lignite spoils have demonstrated that additon of topsoil in the range of 0 to 12 inches in depth have produced plant growth and survival rates in proportion to the depth of the topsoil. All plots had good initial germination rates, but the non-topsoiled area showed an almost 100% mortality rate in a dry year. The explanation of this phenomenon is that the plant roots grew down to a level where water percolation was severely impeded in the non-topsoiled plots, but remained in free percolation zones of the topsoil in the topsoiled plots. One undesirable side affect of the topsoiling procedure was that weed seeds were present in the topsoil; and they germinated, causing the plots to contain some weeds in one of the Colstrip studies.

The Montana investigations demonstrated that yields of plants increased with topsoil addition, but the yield leveled off after topsoil reached a depth of four inches. These investigations also showed that topsoiling very rapidly aided vegetation growth, and therefore helped reduce water erosion as compared to non-topsoiled plots. Weeds were essentially free from topsoiled plots in the investigation.

4. Fertilization

In the North Dakota studies, vegetative yields on test plots increased with additon of phosphorous up until the rate of addition reached 200 lbs/acre. However, additon of nitrogen, as nitrate, did not appreciably aid the yields. This was attributed to the nitrification of geologically formed lower mantle ammonium ions. Which are brought to the surface during mining excavation operations.[134]

The Montana studies indicate that both nitrogen (N) and Phosphorous (P) fertilization is required, on the Colstrip spoils, in order to optimize plant growth. Combinations of 75 lbs/A. or 100 lbs/A N, and either 50, 75, or 100 lbs/A P gave roughly similar yield results.

5. Plant Species Growth Studies

The Montana study investigated the growth potential of plant species allegedly capable of withstanding the semi-arid saline conditions found in the Decker study area. The only grass which showed even partial initial success was tall wheatgrass. Legumes such as Sainfoin, alfalfa, and yellow sweetclover performed quite well, as did greasewood, and to a lesser degree nuttall saltbush in the shrub category. However, second season survival rates are still to be tested.

6. General Observations

The emphasis of these two major studies are in somewhat different areas. The North Dakota study is most concerned with developing soil conditions amenable to long term development of useful plant species. It emphasizes that different depth levels of spoil material may be more conducive to plant growth than others. The finding that sodium levels differ as a function of depth, and that ammonium ions are present at certain depths, implies that aside from topsoils, deep subsoils may provide better plant substrates for reclamation than more shallow subsoils. However, much of the North

Dakota work was performed in laboratories, under better than average conditions, for purposes of isolating effects of single variables. The Montana study has attempted to investigate multivariable changes solely on spoils in the field.

The results of these studies, both of which are continuing, are quite valuable in assessing methods of reclamation for particular sites. The most important results of the studies appear to imply that (1) topsoil must be conserved to as great a degree as possible

(2) subsoil core samples of the mining should be evaluated prior to mining in order to determine which spoils should be replaced at which levels of reclamation (i.e., most saline and toxic at the bottom least saline highest available nitrogen and phosphorous levels at the top, etc.)

(3) physical shaping of the spoils is important in establishing initial germination and plant growth

(4) soil amendements (gypsum, mulch, flyash, etc.) may generate long term improvements in soil chemistry and porosity, but will not alone create suitable conditions for initial plant establishment

(5) in especially dry, saline areas, reclamation may have to proceed through successional changes, (e.g., legumes first to stabilize soils and add organic matter) eventually to be succeeded by more economically desirable grasses.

However, much more work is required to fully assess the long term reclamation potential of particular sites, especially where climatic conditions may show wide variations, and where grazing pressure is to be exerted on the grasses and shrubs which grow on the reclaimed spoils.

C. Reclamation of Mines with Shallow Overburden and Thick Seams

A unique reclamation problem is presented when mines are excavated which have shallow overburdens (20-30 feet), and thick coals seams (70-100 feet). The problem is created because there is insufficient spoil material to fill the pit and allow regrading of the original (or similar) contours. In fact, there is usually only sufficient spoil material to create a gentle slope around the edges of a deep depression. In effect what has been created is an accesible deep hole. Given such a situation, the reclamation options are limited to leaving a deep depression, obtaining the additional material for use as fill, or to allow the hole to fill up with water, and thereby create an impoundment to act as a lake for wildlife use, recreation, or as a reservoir for livestock watering.

However, the depression does not automatically become a high quality lake. The proposed lake site must be considered with respect to many other environmental considerations.[135] There needs to be an understanding of the dynamics involved in the natural filling process. Will the lake fill without creating flood conditions? If long dry spells persist, the evaporation rate will tend to increase the dissolved salts content of the water making it unacceptable as a wildlife or cattle watering place, or as a recreational spot for fishing. If the water in the lake diffuses into the surrounding ground water aquifers, the lake will revert to a dry hole and be subject to natural erosion forces. Therefore, it is necessary to evaluate the probability of success of a lake-type reclamation venture by modelling the precipatation, diffusion, and evaporation cycles for the actual site.

D. Hydrological Considerations

Ground water flows through the most permeable material underground. In many cases, rock above the coal bed or the coal bed itself may act as the conducting ground water aquifer. Upon commencing a mining operation, aquifers are first disturbed when overburden is blasted. This will cause subsidence of deep rock possibly blocking the aquifers beneath the coal seams. As overburden is removed above the seam, water may seep into the pit where it will have to be pumped out thus reducing the ground water recharge at points away from the mining operation. Furthermore, when unconsolidated spoil material is replaced after the coal seam has been mined, the permeability of that stratum (where the coal seam was) will generally be decreased. This is due to the fact that most of the western spoil will be very high in clay content. This decreased permeability will cause impedence of the ground water flow, thus reducing the aquifer recharge rate at points away from the seam. Another possible adverse effect on ground water is that, by requiring it to pass through high sodium (and possibly calcium) spoil material (rather than porous rock or coal) considerable leaching may occur. Therefore, in addition to reduced recharge rates, the salinity of the recharged water may be higher than it was prior to the mining operation.

The effect of blasting on deep aquifers must be assessed on a site by site basis. In fact, as with reclamation itself, the ground water problem is very site dependent.[135] A thorough investigation of the hydrology and geology of a potential mine site is mandatory prior to the onset of mining. Not only must water recharge rates be determined after mining has commenced, but also the water quality implications of changing the chemistry of the substances through which the ground water must flow must be considered.

Although little has been said concerning the environmental impacts associated with in-situ gasification, its major impact will be on the geology and hydrology of the affected area. Because, the gasification reactions are to take place at depths greater than 1000 feet, it is inevitable that aquifers at those and shallower depths will be affected. Blasting will cause subsidence of the entire affected area. As coal reacts in place, voids are created in the coal seam and additonal subsidence will occur. These subsidence occurrences are bound to interfere with the ground water flow. Furthermore, as the reaction product gases percolate upward throughout the broken rock and soil strata, it is quite likely that they will flow through some of the ground water aquifers about the reaction zone. Some of the soluble components of that gas stream including hydrogen sulfide, ammonia, hydrogen cyanide, hydrogen fluoride are likely to dissolve to some degree in the ground water. Should this occur, then a potentially serious toxicity problem would exist for future users of that contaminated ground water.

CONCLUSIONS AND RECOMMENDATIONS

It must be emphasized that much of the data concerning water use and pollutant emissions of the new technologies is in an elementary stage. The developers of the processes have admittedly spent more time attempting to develop economically feasible methods for converting coal to synthetic gas and oil, or to electricity, than with developing comprehensive environmental safeguards. They argue that the pollution control technology ought to be developed as a final phase in the overall process development scheme. However, this may create a dilemma when choices are made by U. S. Government funding agencies concerning the technologies whose funding is to be continued and those that are not.

Each process is characterized by its own economic variables and pollution potential. Unless environmental safeguards are factored into the economic viability analysis of a process, its actual feasibility (from an economic point of view) cannot be adequately assessed. Although the data was found to be "soft", calculations can be performed to give values for some pollutant emission characteristics. Many assumptions were made in assessing emissions and water use for each process. The values given represent estimates and should be used more for determining ball park impact assessments than for determining whether very specific processes, in specific regions, will or will not meet prescribed ambient standards for a given pollutant.

This study will not offer recommendations concerning the most, or least, environmentally desirable processes. Such assessments can only be made by state and local planners, who understand how a specific industrial process will affect a specific geographic location, not only in terms of environmental degradation, but also in terms of social, economic and cultural variables. Therefore, this study may be used as a part of an overall state and regional decision making process concerning the question of how best to utilize the coal resources in the region.

Although recommendations concerning process desirability are not to be made, certain observations about the need for additional research and study will be made.

A. Emission Control Technology Requirements

1) Actual Hydrogen sulfide removal technology should be evaluated for all gasification and liquefaction processes discussed.

2) The fate of hydrogen cyanide, hydrogen fluoride, mercury, and arsenic compounds formed in gasification and liquefaction processes must be determined. It was assumed in this study that most of those compounds from gasification would go to the wastewater pond, but this is not necessarily the case. HCN for example, may be collected with H_2S and passed through the sulfur removal unit and emitted to the atmosphere.

3) Nitrogen Oxide formation in advanced high temperature turbine and MHD technology must be more thoroughly studied.

4) The effectiveness of various evaporation pond linings must be assessed much more carefully than at present.

B. Environmental Effects

1) Careful study must be given to the problem of sulfate formation from SO_2, HC, NO_x, particulate and ammonia emissions from gasification and liquefaction processes.

2) Analysis of the form of trace metal emissions and the fate of those emissions from coal burning facilities should be performed. Especially important is the question of biological conversion of trace metal compounds to more toxic chemical species, which are also

easily transportable via solvation in water or volatilization back into the atmosphere.

3) Analysis should be performed on the possible emissions of various hydrocarbons and inorganic materials from evaporation ponds.

4) Studies concerned with strip mine reclamation techniques should continue with the idea of extending the studies to more than one or two growing seasons. Environmental stresses such as grazing pressure should be applied to test the stability of reclamation experiments.

5) Research should be conducted on the effects of aquifer disruption both from surface mining and reclamation practices.

C. Water Use

1) The effectiveness of dry cooling in minimizing cooling water requirements for gasification, liquefaction, and electric power generation should be further evaluated.

2) A determination should be made of the actual water quality requirements for water used in coal slurry pipelines.

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